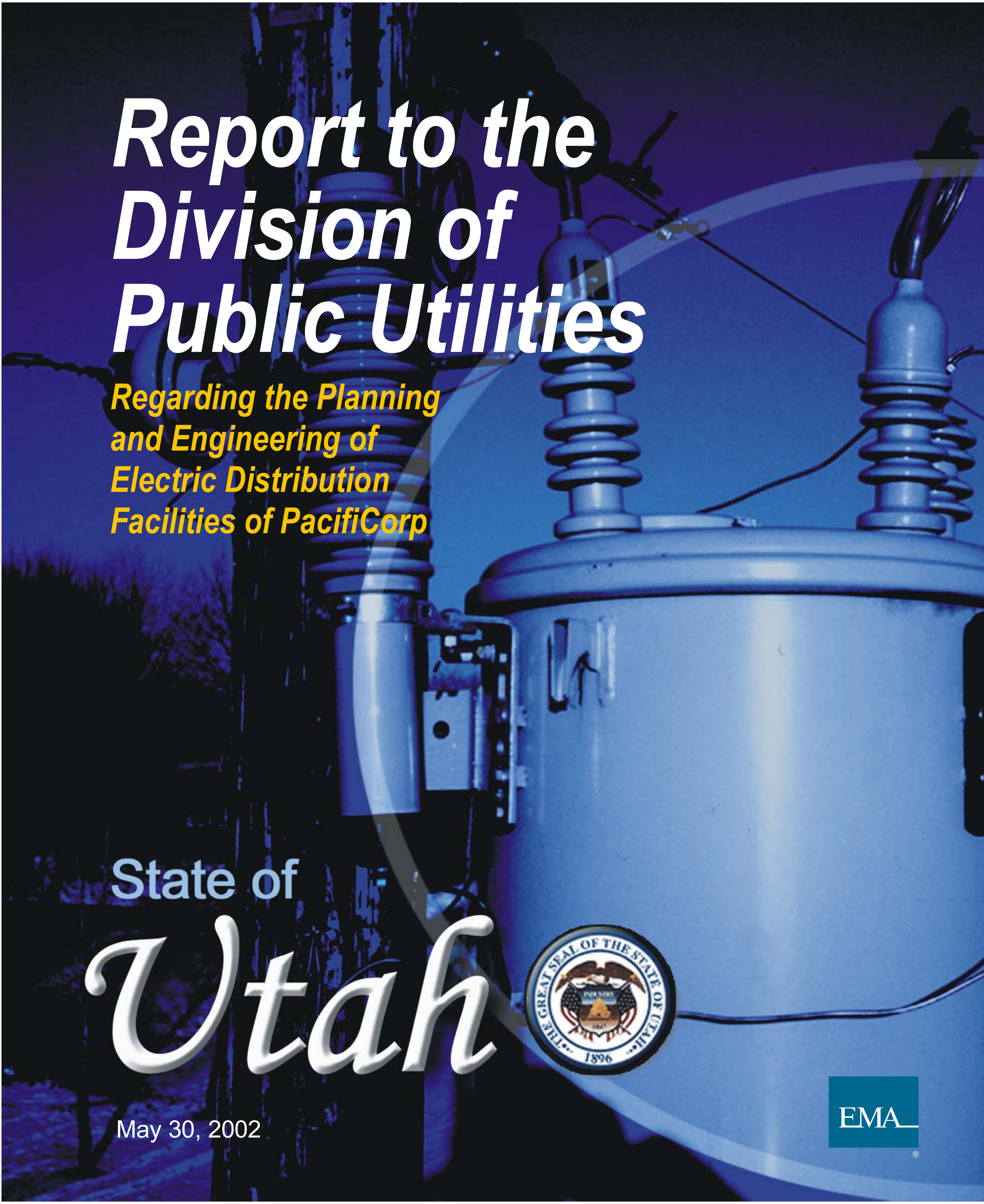

Report to the Division of Public Utilities

Regarding the Planning and Engineering of Electric Distribution Facilities of PacifiCorp

State of

Utah

May 30, 2002

EMA®

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ACKNOWLEDGEMENTS

Projects of this nature depend heavily on participation of all members in order to be successful. Only with the significant collaborative involvement of PacifiCorp could we compile the needed information to be relevant and useful to the Utah Department of Public Utilities' needs. The assistance and insight of Brad Williams and Randy Rhodes of PacifiCorp were greatly appreciated.

The authors of this report gratefully acknowledge Salt River Project and Puget Sound Energy's participation in providing information targeting specific requirements, which added depth and insight into their Electric Utility practices, policies, and procedures. A special thanks is extended to the efforts of Kenneth Alteneder of Salt River Project and Jennifer Tada of Puget Sound Energy.

The advice and help of the Utah DPU staff in providing input to the study direction was also appreciated. Marlin Barrow, the project manager, is especially noted.

EMA researchers include Thomas A. Kerestes, principal investigator and project manager, with support from John D. Winter, Thomas Nigon; and Dr. Linda Paralez.

1 EXECUTIVE SUMMARY

INTRODUCTION

Load growth along the Wasatch Front in Utah has been significantly high. In part, this load growth caused PacifiCorp to commence 150 major construction projects, scheduled for completion in mid-summer 2001.

Possible above-normal temperatures occurring in the summer of 2001 combined with construction delays, prompted concern within PacifiCorp. PacifiCorp issued a press release encouraging customers to conserve energy in six major areas in and around Salt Lake City. This was reported in the local press as a warning of potential electrical outages.

The Utah State Division of Public Utilities (DPU) retained EMA, Inc. to investigate PacifiCorp's electric distribution planning and engineering practices relative to the Wasatch Front in the State of Utah in a collaborative manner. This involves the entire panorama of activities relative to distribution planning, construction, and operations and maintenance. The work was accomplished between the Utah DPU, EMA, and PacifiCorp, beginning in late November and completing by May 2002.

EMA approached the problem by identifying the various "drivers" behind the article appearing in the May 25, 2001 Utah Desert News, "Blackouts Could Hit Thousands of Utahns". The article was based largely upon a PacifiCorp press release regarding the potential for six areas along the Wasatch Front being in jeopardy of facing potential outages, if the weather remained hot during the summer of 2001.

Based upon these drivers identified through the investigation of the six trouble areas mentioned in the press release and upon other information gathered on-site, EMA investigated four functional areas of PacifiCorp for the purpose of identifying potential improvements within PacifiCorp's electric distribution area. These four areas were (1) load forecasting; (2) planning; (3) engineering; and (4) benchmarking. Following is a discussion and summary of the recommendations for each of the functional areas.

LOAD FORECASTING RECOMMENDATIONS

Generally, asset investment in the electric distribution system begins with the project planning process. The planning process is initiated in one of two ways: (1) by increasing load levels; or, (2) by aging or outdated facilities, referred to as plant investment or assets. The improvement projects initiated by higher anticipated load levels are driven by the load-forecasting function within PacifiCorp. The load forecasting methodology utilized by PacifiCorp thereby becomes a factor in the initiation of improvement projects, particularly the timing of when the project construction completion is required.

Employing accurate and proven techniques relative to load forecasting will ensure proper lead-time is achieved for the construction of new or replacement facilities. Subsequently, this ensures reliable and continuous electric service to all of PacifiCorp's customers. This study investigated the load forecasting methodology PacifiCorp utilizes and how they are improving their processes and techniques.

It was found that PacifiCorp's load forecasting techniques, prior to the summer of 2001, were insufficient for the geographic area along the Wasatch Front of Utah. The delay in substation and distribution facility construction completion dates generated a need to acquire approval and funding authorization from local communities in a rather hurried fashion, resulting in strained customer relationships and little time for obtaining consensus on the course of action needed. As will be detailed in this study, PacifiCorp has moved to mitigate these load forecasting deficiencies through the implementation of the ASEA Brown Boveri, Ltd. (ABB) FORESITE load forecasting computer tool.

The following recommendations are summarized with respect to the load-forecasting function.

Recommendation #1: Continue to Improve Load-Forecasting Abilities at PacifiCorp

Continue with the current direction of improving load-forecasting abilities within PacifiCorp. This can be accomplished by either expanding on the current ABB forecasting knowledge base or by assuming the function within PacifiCorp. If used, training on the use of the ABB FORESITE load forecasting tool will be required.

Over the course of the study period, PacifiCorp has expanded its load forecasting ability in the direction of creating a data warehouse that will contain load information from various sources. The data warehouse will be linked to other applications, allowing interfacing of shared information. Through this action, a more homogeneous and consistent planning function might occur.

Additionally, efforts are underway to improve community communication interplay. This allows for an exchange of information relative to system improvement projects and how they might impact a local community.

An additional effort introduced by PacifiCorp is a community information program. This will effectively create and promote a planning partnership between PacifiCorp and local communities. The purpose is to present PacifiCorp's

Wasatch Front growth projections to the public for feedback and validation. Under high growth situations, it might appear to communities that there is constant construction underway. Communication efforts such as these go far to alleviate concerns. Such communication efforts will create a stronger link between the economic forecasting used by Wasatch Front communities and PacifiCorp planning activities. This should eventually lead to more accurate load forecasting information for planning purposes and increase the regional and community planning accuracies.

Recommendation #2: Establish Load Forecasting Benchmarks

While PacifiCorp does participate in several benchmarking efforts, it should seek to establish benchmarking criteria associated with load forecasting. The goal would be to determine how closely "forecasted" loads match "actual" loads.

Tracking such information is the only manner in which it can be known whether or not the load forecasting accuracy is improving over time. It will be necessary to track this on a winter and summer basis, with most weight given to the summer peak loading conditions. Actual versus forecasted loads should be monitored on a semi-annual basis.

The difficulty of tracking forecasts versus actual consists of all the variables existing on both sides of the equation. The forecasts need to look for unexpected load additions; these could come from government incentives or a regional or national upturn in business activity. Additionally, the weather conditions are quite variable, with some year's temperatures hitting the ten-year high levels several times that very year.

Switching load between various substations and feeders to maintain service to customers or to transfer load for construction purposes complicates actual load level readings. Such load readings must be "pasteurized" or cleaned to account for such switching issues. Nevertheless, there must be some method devised that will allow for a determination as to how accurate the load forecasting function is within an electric energy provider's service territory.

DISTRIBUTION PLANNING RECOMMENDATIONS

The second manner in which the asset improvement projects are initiated would be as a result of aging or outdated facilities. There might exist varying causal elements as drivers, examples of such drivers would include: (1) low voltage on portions of the distribution line due to small conductors; (2) aging facilities such as those composed of old poles that are deteriorated and in need of replacement; or, (3) inadequate components that are substandard in quality of design or provide poor performance, e.g., certain devices that might be recalled by the manufacturer.

The engineering or design departments within an electric utility would normally initiate these types of projects, however the operating departments may also provide input from their field experiences. Engineering tools are used to model the distribution system. These tools indicate the weak portions of a distribution system when the load levels are increased. This study examined the planning and engineering departments of PacifiCorp to determine the methodology used. In particular, the processes employed to move a project through initiation; engineering planning; engineering design; permitting; and construction at PacifiCorp were examined.

The acquisition by ScottishPower has caused some reorganization within PacifiCorp. A five-year Transition Plan was created and is now being implemented throughout the PacifiCorp territory. This entails centralizing management into the Portland area. One notable change is the creation of the Asset Management department.

In an electric utility, capital investments are funded from a single source. That means funds will be allocated to different departmental needs, i.e., those of generation, transmission and distribution; as well as internal needs such as Information Technology expansion or Communication Infrastructure investments. This funding aspect (how money is allocated to the various needs within PacifiCorp) has not been investigated, due to this project scope and budget restrictions.

However, the creation of the asset management group is a common trend in the electric utility industry. It allows for one central group to be responsible for how much is allocated to the various needs within a departmental area. It holds the purse strings and devises the rules and guidelines by which the funds are allocated. It oversees the business case justifications for new capital investments. A discussion of the asset management department is included in this report. As with any major organizational change, there are some disruptions likely to occur where processes or communication links may break down as individuals assume new roles and responsibilities.

PacifiCorp is a mature electric utility continuing toward restructuring as an asset management driven organization. It possesses the expertise to conduct planning studies in a methodical manner that ensures needed projects are properly planned and initiated for construction. Nevertheless, here are some recommendations that can promote higher reliability and customer service.

Recommendation #3: Strengthen Load Growth Projections Emanating from Field Offices

While there is a process in place for formal reporting from the Field Engineers to the Asset Management Department, there should be a more thorough reporting of feeder growth from field employees to the Field Engineers. Additional training may be required of the individuals holding Field Engineer positions in order to increase the confidence level in the data received by the Asset Management department.

Additionally, with the creation of the distribution model in the ABB FORESITE tool, there occurred communication with approximately 50 public agencies along the Wasatch Front. The field personnel can represent PacifiCorp in obtaining this local public information and reporting it to the asset management department. Generally, justification of projects will not be adequate without load projections and input from field personnel.

Recommendation #4: Develop Distribution Automation Standards

PacifiCorp has been studying Distribution Automation (DA) in some areas of their service territory. They should consider development of a Standard for distribution automation and utilize the Standard in their planning process. This involves establishment of a communication protocol, device sensing and control selection, determination of data collected, and economic evaluation of sectors to be automated.

Distribution automation along the Wasatch Front is useful in areas where there are loop feeder capabilities, not on radial feeders, where there exists little feeder or substation sectionalizing capability.

Recommendation #5: Develop Formal Feeder Sectionalizing or Breakdown Analysis Sheets for Outage Restoration Work

PacifiCorp should develop a formal documentation for sectionalizing of substation and feeder during outage contingencies. These documents should be available to system operations dispatchers to be used to restore power. These documents should be adequately updated and maintained.

The Field Engineers have the most knowledge of the system they oversee. Therefore, PacifiCorp relies on the availability of the Field Engineer for information during outages. However, the Field Engineer may not be available at all times due to vacations and other circumstances that may take the Field Engineer away from the work area.

Recommendation #6: Review the Planning Process in Relationship to Construction Lead-Times

PacifiCorp should review the overall timing involved in the planning study process and the time required for project approval. This involves approving construction for new substation capacity additions at least two years prior to the need of the project.

The approval date of the planning study reviewed in this report was less than one year before the projected overload date of the substation and the projected completion date is one year after the substation could be overloaded. It is believed that better load forecasting techniques will mitigate this issue by providing earlier notification and thereby satisfying the required construction lead time.

Recommendation #7: Plan for Minimizing Outage Restoration Duration

It is understood that when mobile transformers are installed, it will normally consume approximately six to eight hours. However, due to outages occurring on nights and weekends, compounded by long drive times, the outage duration may extend to 14 hours.

Nevertheless, it is recommended that PacifiCorp review its outage restoration procedures in an attempt to reduce the planned outage duration to be less than 14 hours maximum. Shorter outage durations would likely increase customer satisfaction.

Many of PacifiCorp's substations are of a radial nature, so as growth continues, it should prove beneficial and more economical to loop feeders. This action will effectively act to reduce the dependencies now placed on mobile substations and spare transformers.

Recommendation #8: File for the Creation of an Undergrounding Surcharge by Franchise in Utah

PacifiCorp should propose, and the Public Service Commission should consider authorizing, an underground surcharge rate for customers within underground (UG) franchises such as Sandy and Draper to keep rates and benefits to all customers equitable. Cities could establish UG districts allowing PacifiCorp to collect a small surcharge from customers within that city.

The City can use these collected funds toward undergrounding existing lines or for paying the difference of UG to overhead (OH) for new lines going through their UG district. If there is insufficient money in the fund, PacifiCorp might advance or finance the costs to be paid back from the surcharge over some specified period of time.

DISTRIBUTION ENGINEERING RECOMMENDATIONS

Accurate assessment of distribution equipment capacities is crucial to system planning. Responsibility for this function as it applies to distribution substations overlaps between Distribution Systems Engineering and Area Planning Engineering. The Field Engineers and designers are essential for proper planning, particularly crucial in a time of high load growth.

Additionally, these positions at PacifiCorp are working with software applications that require multiple data entry. The GIS application is one example and the integration into SAP is another.

Recommendation #9: Review Field Engineer Staffing Levels

It is recommended that PacifiCorp review the staffing level of the designers and field engineers in the areas where the load is growing at a faster than average rate. These positions require at least four years of special training to be proficient in the required skills. PacifiCorp should consider increasing these staffing levels, since the growth is projected to continue at the current rate for the next few years.

In the event PacifiCorp chooses to outsource this function, it will still be necessary to train the outsourced personnel in the processes and procedures currently employed.

Recommendation #10: Migrate to One GIS Mapping System

Continue to migrate from several mapping systems including AutoCAD and ABB FEEDER-ALL to one GIS mapping system. PacifiCorp should strive to involve the necessary employees in this transition to ensure the GIS mapping system can replace the AutoCAD and FEEDER-ALL maps. Acceptance of new systems by being a part of its creation is a key element to successful implementation.

Recommendation #11: Provide Tighter Integration into SAP

PacifiCorp should continue to integrate the cost estimating, mapping, and tracking programs into SAP to eliminate the need for the same data to be entered in multiple programs.

BENCHMARKING RECOMMENDATIONS

At the Mid-Course Review Meeting in Salt Lake City, Utah, it was decided that additional information should be gathered on Demand Side Management (DSM) initiatives at other Utilities. Puget Sound Energy (PSE) of Bellevue, Washington was selected as a site for collecting this information, as they had been named Utility of the Year for 2001 based upon their DSM efforts. PSE accepted the request to be interviewed relative to their DSM work and the information gathered is included as a part of this report in the Benchmarking section.

Recommendation #12: Monitor the Average Substation Utilization Level

Salt River Project (SRP) has extensive research and data relative to how high the substation utilization metric should be set to both minimize asset investment and provide adequate customer service. They found the average substation utilization level should not exceed 88 percent of transformer nameplate rating. SRP has a homogeneous service territory with large switching capabilities between feeders and substations, while PacifiCorp has many radial feeders.

In the meantime, PacifiCorp is currently moving toward a more active role in development of a load forecasting model that should eventually enable better forecasting. They will operate at higher average substation utilization levels. This may or may not be commensurate to their load forecasting abilities. Load forecasting is a key element in successfully achieving (and maintaining) higher average substation utilization levels.

Assuming PacifiCorp follows their current capital investment initiatives, by 2006 the Wasatch Front substations will be loaded from the current 62 percent to an average substation utilization level of 76 percent. This may or may not represent a sufficient amount of time (four years) for PacifiCorp to increase their load forecasting reliability.

Recommendation #13: Increase Demand Side Management Programs

PacifiCorp had implemented a demand side management program that allowed for a reduction in a customer’s energy bill of 20 percent or 10 percent if they reduced their consumption respectively by 20 percent or 10 percent of the previous year’s usage. The results from this action are dependent upon weather conditions and require weather normalization techniques to determine it’s overall impact on energy savings and demand reduction. However, it had a favorable response from their customers, who in Utah, participated at a rate of about 25 percent. This indicates there is a significant component of the general population who are receptive to conservation initiatives.

It is recommended that PacifiCorp consider a more aggressive position on Demand Side Management programs. The examples set by Puget Sound Energy have achieved measurable savings, both in shifting demand and reducing overall energy consumption. This has begun with the issuance of a “Request for Proposal” that provides for a pilot project to obtain direct control of residential air conditioners. These appliances have become a large energy consumer and demand creator over the past few years, with use of “swamp air conditioners” diminishing.

Recommendation #14: Investigate Distributed Generation Opportunities

It is recommended that PacifiCorp examine promoting the use of distributed generation among its Commercial and Industrial customers. This entails such activities as: (1) the analysis of where/if distributed generations (DG) would be most effective on their distribution system; (2) the determination of the tangible and intangible economic value of DG to PacifiCorp at those locations; (3) the method that DG would be controlled, if controlled centrally for economic or area dispatch; (4) the creation of rates that would be incentives for customers to install DG at their premise; and, (5) the development of a marketing/communication plan for full rollout and implementation.

UTAH DPU PROJECT REQUIREMENTS

The State of Utah issued a Request for Proposal, RFP LW2004 “Consulting Services to Report to the Division of Public Utilities Regarding the Planning and Engineering of Electric Distribution Facilities of PacifiCorp,” for the purpose of retaining an expert(s) to report to the Division on the effectiveness of electric distribution planning and engineering of PacifiCorp along the Wasatch Front in the State of Utah. The DPU subsequently modified the requirements to contain the following work plan.

Work Plan

Organization and Planning

Discussion of overall project scope, schedule agreement and travel arrangements. Establish final timelines.

Analyze Six Trouble Areas

No physical field check will be performed. Prepare for meeting with PacifiCorp, and interview PacifiCorp via phone. Determine why these substations were considered trouble areas.

Meeting to Gain Consensus

Draft document of questions that will be reviewed with the DPU and responded to by PacifiCorp. This process will allow PacifiCorp to understand what type of information will be needed for the next phase.

Distribution Engineering Investigation at Portland and Salt Lake

Prepare for the trip to Portland, and then interview PacifiCorp in Portland for two days and in Salt Lake City for an additional day.

Analyze Load Forecasting

Document source of load data for load forecasting; determine data ownership; and define load data modeling tools used by PacifiCorp. Summarize work and report.

Analyze Distribution Planning Process

Determine data input, threads and linkage. Review planning criteria and parameters for selection of alternatives. Summarize work and report.

Analyze Engineering Process

Document loading criteria and check emergency equipment stock and spare equipment levels particularly transformers, regulators and distribution feeders. Summarize work and report.

Mid-Project Check

Discuss the project progress with the DPU, and current work will be re-evaluated. Summarize the work to date and confirm course of action.

Analyze Distribution Budgeting Process

No work will be performed on Distribution Budgeting Process other than to gather data to determine if further work might be required.

Benchmarking

Determine if PacifiCorp performs routine benchmarking. This task will check for internal metrics and research other utilities. Summarize work and report.

Final Draft Report

Compile all data, preparation work, and hold meetings to agree on content. Summarize work and report. Present the final report via a web conference.

NEWS ARTICLE INITIATING ACTION BY DPU

The section includes the news article in which PacifiCorp issued a warning of six possible troubled area substations. The article was obtained from Deseretnews.com Friday, dated May 25, 2001. The news article was based on a press release issued by PacifiCorp, which in summary form stated:

- Early high temperatures along the Wasatch Front are beginning to stress certain areas of Utah Power's distribution system. Temperatures approaching 90º F may cause localized power outages. Normal temperatures this time of year are 75º F. The record high for this date is 90º F.
- Utah Power is in the final weeks of completing some 150 major construction projects along the Wasatch Front, valued at $45 million, to address rapid growth.
- In these areas, customers are requested to reduce electric use as much as possible. If temperatures continue in the high 80s or 90s, outages will likely result if electric demand is not reduced.
- Utah Power is providing early notice of these issues in hope that customers will help reduce electric demand and ease the pressure on the system during the final phase of construction.

This is the news article as it appeared in the local press.

Blackouts Could Hit Thousands of Utahns
Construction projects, high temperatures may cause hours of outages

By Brice Wallace - Deseret News business writer

Customers served by six Utah Power substations face potential outages if the weather remains hot.

About 150 major construction projects to boost the company's systems in Utah have left Utah Power without automatic backup systems normally in place. That, combined with above-normal temperatures, could spell trouble.

"There have been no outages, but these areas are really operating near their maximum capacity" company spokesman Dave Eskelsen said.

"If we have problems due to excessive heat the outages may be quite lengthy, perhaps a couple of hours. We're watching these areas quite closely because the equipment there is delivering on maximum capacity and the construction projects rating are not quite finished."

That work is expected to be complete in mid-June. It involves activities at 33 substations and 115 transmission lines. The projects, costing $45 million, will add 405 megawatts of capacity to the system.

The trouble area substations include:

- *Sandy: South Towne Mall area, commercial park and Sandy City Hall*
- *Oquirrh: 8400 South to 10900 South and 2700 West to 7200 West*
- *Vine: 900 East to 1300 East and 4500 South to 6600 South*
- *Hoggard: 5415 South to 9000 South and 3800 West to 8000 West*
- *South Mountain: 12300 South to Point of the Mountain and 3000 East to I-15. It may include Big Cottonwood Canyon*
- *Riter: 4400 West to 5600 West and north of 2100 South*

Each substation serves between 800 and 2,000 customers.

Temperatures in Salt Lake topped 90 degrees Thursday, when the normal high for the day is about 75. The high temperatures can lead to overloading of the electrical system, but the company is hoping customers cut back on their usage during those periods to alleviate the chance of outages.

Eskelsen also noted that the trouble is related to local demand and is not similar to outages occurring in California that are caused by a lack of power generation.

"Everything is dependent upon the weather," Eskelsen said. "A little moderation on the part of a lot of people in these areas will be very helpful."

Also helping PacifiCorp is the resolution of trouble at its Hunter Power Station. The facility is back to regular operations now that a unit shut down from a November 24 short has been repaired.

But it will be at least a few months before customers in Utah and other states learn the exact costs of repairing the 430-megawatt unit and replacing the power lost because of the unit's shutdown.

The company has said it was costing about $1 million per day, meaning the price tag could be in the range of about $160 million.

"The costs will be spread throughout the PacifiCorp territory according to lower cost allocations," Eskelsen said. All our generating units technically serve the entire service area. The costs won't be borne by Utahns exclusively because this is a base-load resource."

The plant, near Castle Dale, suffered a short in one of three generation units, but the repairs were made within the four- to six-month time frame forecast by the company in late November. Commissioning of the repaired unit occurred earlier this month.

That unit is one of three at the 1,240-megawatt, coal-fired plant and produces five percent of the total power from ScottishPower's PacifiCorp business.

"It's an extremely labor-intensive enterprise to rebuild a generator," Eskelsen said. "It has a tremendous number of parts. It's a specialty enterprise. People have essentially been working on it around the clock from Westinghouse, the manufacturer, from the day it was shut down until it was restored in late April, early May."

The company replaced the lost power from both its own resources and by buying power elsewhere.

"It was a significant hole in our resource mix," Eskelsen said. "Luckily, during that period, at least in Utah and the Mountain states, it was not during our peak season of demand. The loss of a unit like that in summer would have been a lot more serious."

PacifiCorp is tracking the actual costs for its power purchases in the open market through a deferred accounting procedure. A pending rate case before the Utah Public Service Commission will be decided by September, although the commission already has granted about half of the request on an interim basis.

Key Reasons for Proclaiming these Potential "Trouble Areas"

The reasons for PacifiCorp proclaiming these as potential trouble areas were outlined as:

- Abnormal system conditions due to 150 major construction projects underway
- Above-normal temperatures
- Currently these areas are operating near their maximum capacity

Utah Division of Public Utilities Perspective

The Utah Division of Public Utilities (DPU) views excessive having six different areas designated as "troubled areas" and, through this RFP LW2004, desires to determine the exact cause that each of these areas were declared to be in jeopardy. Furthermore, DPU is seeking a deeper investigation, of the distribution

(a) load forecasting; (b) planning; and, (c) engineering areas the key sources generating this problem might be identified and eventually eradicated through collaboration with PacifiCorp. Additionally, a fourth item, investigating benchmarking or best practices at PacifiCorp has been requested in an effort to improve distribution practices within PacifiCorp.

The DPU is indirectly seeking to answer such questions as the following, in a manner that will be embraced by PacifiCorp:

- Is the distribution plant adequate or not?
- What can be done as remediation toward any disparity in the existing distribution plant or in the existing operating practices/policies of PacifiCorp?

GENERAL PACIFICORP BACKGROUND INFORMATION

PacifiCorp is a multi-jurisdictional utility, subject to regulation in six states, as well as by the FERC. PacifiCorp is headquartered in Portland, Oregon; with Salt Lake City serving as the regional main office for the Utah division and operates as Utah Power & Light (UP&L). ScottishPower now owns PacifiCorp. The Company serves a total of 1.4 million customers, with the Utah customer base (as of July 2001) as follows:

Residential……………………	589,251
Commercial…………………..	61,091
Industrial………………………	8,289
Public St. & Highway Light…	2,782
Other Public Sales…………..	28
TOTAL…….	661,441

In 1999, the Utah Public Service Commission approved a merger between PacifiCorp and Scottish Power, a multi-utility company headquartered in Glasgow, Scotland. As a condition of the merger, PacifiCorp agreed to certain performance standards and service guarantees that would not allow distribution outages to increase above current levels. A recent report of these standards is included in the Appendix. The implementation of CADOPS (an automated process of linking customer count to distribution feeder) has resulted in a more accurate count of customer outage data. This required a recalculation of the baseline numbers from which to calculate performance improvement.

On or about May 25, 2001, PacifiCorp advised its Utah customers living along the Wasatch Front (an area of approximately 60 miles from Ogden, Utah on the north to Provo, Utah on the south) that there could be local outages if distribution loads exceeded anticipated limits because six construction projects at distribution substations had not been completed.

On or about June 21, a windstorm along the Wasatch Front caused about $1 million in damage to homes and trees. As a result, some PacifiCorp customers were without power for up to 48 hours. This was deemed a "major event" by PacifiCorp.

PacifiCorp's Vice-President of Distribution, Bob Moir, is located in Portland. Most of the management personnel are also located in Portland.

Transmission and Distribution Operational Statistics

- 84 facilities
- 3 regions – Pacific, Utah, Rocky Mountain
- Head Office activities across 33 locations
- 117,000 square miles of territory
- 6 union contracts
- Asset Base (plant and machinery) of $3.7 billion
- Customer base of 1.5 million

Transmission Plant

- 15,000 line miles
- 294 substations

Distribution Plant

- 44,000 line miles overhead
- 10,000 line miles underground
- 928 substations

PACIFICORP FIVE-YEAR TRANSITION PLAN

The merger of ScottishPower and PacifiCorp produced a Five-Year Transition Plan that is being followed by the organization as closely as possible. It has several goals to be attained by 2004, as listed below.

- Annual operating cost savings of $300 million from the 1998 level
- Annual capital expenditure reduction of $250 million from the 1998 level
- Employee reductions of 1,600 (costing about $185 million)
- Training and technology investment of $150 million over five years
- Customer commitment investment of up to $55 million

Operating costs may likely be achievable over a five-year period, as employee reductions constitute a large percentage of that value. However, capital expenditures are to be reduced by nearly 45 percent through: (1) better procurement; (2) better contractor management; and, (3) more focused expenditures. These efforts will require considerable overhead to achieve, while at the same time implementing a 1,600-employee reduction program.

The transition plan enablers fall into these overlapping categories as shown in Table 2.1 below.

Enablers	Examples
Development of people	Management development, skills training
Implementation of technology – usually IT	Call center technologies, network monitoring technologies
Investment in facilities	Open Learning, Training Centers
Investment in information and knowledge	Benchmarking
Cultural interventions	Management behavior, employee communications, corporate identity
Personnel interventions	Management recruitment and insets
Injections of high level expertise	Use of consultants
Cash payments	Early retirement payments, severance payments, negotiated changes to union contracts

Table 2.1 Transition Enablers and Associated Examples

Business Unit Relocations

Table 2.2 below highlights the shift in business units residing in the State of Utah from prior to the Transition Plan to after the implementation of the Transition Plan.

Business Units	Stay in Utah	Loss for Utah	Gain for Utah
Corporate Office		X	
Production HO	X		
Distribution HO		X	
Customer Service Center		X	
Income Collection Center			X
Community and Economic Development			X
Transmission Dispatch		X	
Distribution Dispatch	X		
WES		X	
Metering Business			X
Transport Business			X
Mining	X		
Procurement		X	
Training			X

Table 2.2 Organizational Changes by Geographic Areas

This change in organizational structure, combined with commitments to reducing resources, has created significant opportunities for breakdowns in communication as individuals assume new roles and responsibilities. However, while there are some indications this has occurred, PacifiCorp is managing through the transition. One area where breakdown has occurred is the load forecasting area. This will be discussed in more detail in section 5 – Load Forecasting of the report.

3 ORGANIZATIONAL OVERVIEW

BACKGROUND

Utah Power and Light had been acquired by PacifiCorp in the mid-90's, which itself was acquired by ScottishPower in the past two years. During these ownership transitions, the name "Utah Power and Light" has been retained for brand identity purposes as the regional electric provider in the State of Utah. However, for all intents and purposes, the sole electric provider to the State of Utah is PacifiCorp. Therefore, the name employed for the electric energy provider throughout this report will be PacifiCorp.

The management of PacifiCorp is centralized in Portland, OR, and becoming more so by design. Relocation of many of the former Utah Power and Light management to Portland is ongoing, with overall direction concentrating in that geographic location. Various levels of expenditure authorization exist at PacifiCorp. Lowest levels of expenditure are within the local management group in Utah, the senior management in Portland has higher levels, but highest expenditure limit authorization requires the approval of ScottishPower in Scotland – the ultimate owner.

For the purpose of this report, the relevant major organizational components are shown in Figure 3.1 below at a high level.

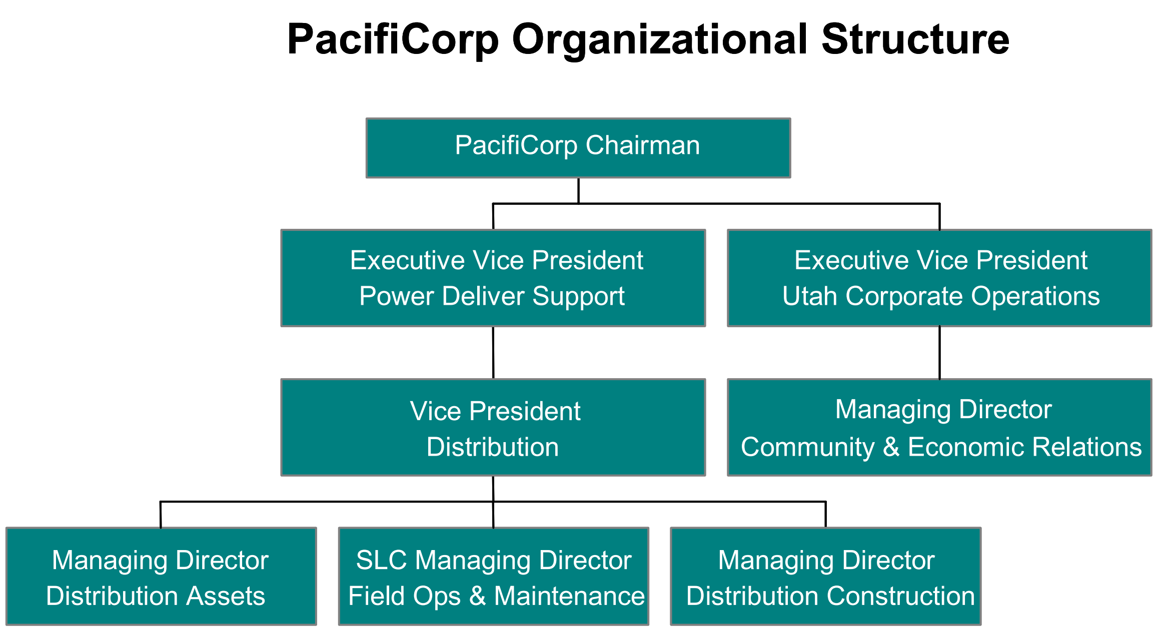

Figure 3.1: PacifiCorp High-Level Organizational Structure

The investigation of this study most directly related to two departments within the Distribution division of PacifiCorp's Power Delivery business unit. The first is the Asset Management Department under the leadership of the Managing Director – Distribution Assets. The second is the Construction Department, under the leadership of the Managing Director – Distribution Construction, as shown in Figure 3.1. These are briefly described below.

Asset Management Department

The asset management group consists of about 100 employees. This group is considered the owners of the power delivery infrastructure. Asset Management is responsible for the effective and efficient planning and management of the Company's entire distribution system infrastructure. The group establishes and implements policies and develops operational initiatives to improve business processes, while setting the strategic direction for the Distribution business. For delivery of the services necessary to build and operate the assets, Asset Management is dependent on Construction and Field Operations.

Four departments exist within Asset Management. They are briefly described below.

Asset Planning

Asset Planning manages long-range investment planning, annual capital budgeting, controlling and authorizing of capital expenditure, and issuing the standards and installation policies to which T&D investments are built. The functional responsibilities are shown in Figure 3.2 below.

Director – Asset Planning

- Capital Plans
- Condition Profiles
- Investment Policy
- Capex Controls
- Asset Programs

Figure 3.2: Asset Planning Functions

Asset Policy

Asset Policy is responsible for four maintenance policies and budgets: user support for operational IT systems, documentation control and publication services for all Distribution Standards, and management of the joint use of PacifiCorp facilities. The functional responsibilities are shown in Figure 3.3 below.

Director – Asset Policy

- Standards
- Maintenance
- Construction
- Documentation
- Inspections
- Specifications
- Policies & Procedures

Figure 3.3: Asset Policy Functions

Infrastructure Planning

Infrastructure Planning provides load forecasts, five-year studies, and area planning services to ensure the network meets reliability and utilization targets. The functional responsibilities are shown in Figure 3.4 below.

Director – Infrastructure Planning

- Network Design
- Design Standards
- Substation Loading
- Operational Telecommunications
- Load Analysis
- System Security
- Major Connects

Figure 3.4: Asset Infrastructure Planning Functions

Safety & Environment

The Safety & Environment department section manages safety, environmental and occupational health issues to meet safety goals and legislated obligations. The functional responsibilities are shown in Figure 3.5 below.

Director – Safety & Environment

- PD Safety & Environmental Management Systems
- Spill Tracking/Reporting
- Injury & Illness Tracking/Reporting
- Procedure Standards
- Tool Standards
- Training & Assessments
- Bird Power Line Program
- Industrial Hygiene Issues
- Waste Management
- Ergonomics

Figure 3.5: Asset Safety & Environment Functions

Construction Department

The construction group or wires area acts as a contractor to the asset management group. This group does the inspection work and can do construction work if time permits. PacifiCorp crews or contract crews do the work. The wires group includes the field operations areas. They provide feedback to the asset management group on plant condition or loading problems.

PacifiCorp has dispatch centers located in both Portland and Salt Lake City. They use an outage management system from ABB called CADOPS to record outages. They use a software product called PROSPER to record outage cause and to create reports. They are currently investigating the purchase of a new SCADA system.

ORGANIZATIONAL STRATEGY

Management decisions within Power Delivery business unit are guided in two ways. First, the transition plan developed during the Scottish Power acquisition provides a five-year framework governing strategic changes in organizational structure, staff counts, and capital expenditures. Secondly, operating plans are developed each year and coordinated from the smallest departments, up to the business unit level. These reflect the transition plan goals and strategies and are formally approved at the onset of each fiscal year (beginning April first of each calendar year).

BUSINESS VISION AND GOALS

On May 3, 2001 ScottishPower Chief Executive Officer, Ian Russell concluded with the following two paragraphs in the 2000/2001 Annual Report Statement:

> *Creating shareholder value is a central objective for ScottishPower. It is one of the key yardsticks the management uses for setting targets and evaluating progress. Against the benchmark of total shareholder return, this year's performance has been lackluster.*
>
> *The goal now for ScottishPower is to resume delivering value and earnings growth. We are structured around three divisions and increased profitability is our top priority. We are re-shaping and improving the performance of our businesses and have focused on energy and the opportunities to create value that arise at each point in the chain linking fuel, generation, commercial and trading, and energy supply. At the same time we will add new businesses that build upon the integrated energy value chain.*[1]

In the same Annual Report, the US Division (consisting of PacifiCorp operations), reported strong economic growth and abnormal temperatures that led to retail demand and sales revenue increases of 6 percent. The PacifiCorp Transition Plan progressed with a reduction of 420 employees (234 were expected). Operating cost savings of $85 million were achieved in the first year. Initiatives have commenced to reduce coal costs, centralize procurement practices, create global product sourcing and reduce layers of management.

ScottishPower's Vision and Values

ScottishPower has reconfirmed its vision for 2005[2] as:

- An internationally acknowledged leader in utility and related services
- In world "Top 10" of utilities and related companies
- Serving customer base of 10m with multiple products
- Recognized for its record of value creating growth and innovation

This vision is qualified by the ScottishPower values guiding its style of doing business and brings balance to its business approach. The values are:

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[1] ScottishPower Annual Report & Accounts/Form 20-F 2000/2001

[2] PacifiCorp Transition Plan – Vision and Strategy

Well-Earned Customer Loyalty: We shall deliver quality and value for money services, which meet and influence our customers' needs.

Enhanced Shareholder Value: We shall create shareholder value by building businesses and continuously seeking opportunities to gain advantage over competitors.

Positive Working Environment: We shall seek to provide a positive working environment, which inspires employees to fulfill their potential and maximize their contribution.

Trust of Communities: We shall maintain the respect and trust of all communities through recognizing and responding to the needs of both the local and wider environment.

Teamwork And Leadership: The ScottishPower group will be led by a management team who:

- Have a passion to deliver
- Are ambitious, honest, frank and ethical
- Share a common sense of direction
- Manage change and have the courage to confront difficult issues and situations
- Are able to take, and encourage others to take, considered and acceptable risks
- Never forget that people do it all

The realization of the vision is PacifiCorp's key contribution to supporting ScottishPower's US strategy. The Transition Plan sets out how the core business is to be reshaped and how utilization of its existing assets is to be maximized.

The vision and strategy for PacifiCorp are centered on the public commitments made at the onset of the merger approval.

4 ANALYZE SIX TROUBLE AREAS

The Utah DPU viewed the press release by PacifiCorp announcing six different areas along the Wasatch Front in Utah being designated “troubled areas” as excessive. As such, the DPU sought to determine the causal elements driving these areas to be declared operating in jeopardy during the summer of 2001. The DPU was concerned that underlying systemic factors might be the real cause for PacifiCorp issuing the press release. Therefore, the DPU felt a deeper investigation of the electric distribution; (a) load forecasting, (b) planning, and, (c) engineering areas, was warranted. In gaining knowledge of the causal elements, the DPU in collaboration with PacifiCorp, might identify and establish mitigation plans to alleviate future such situations. Each of the six trouble areas were examined as to the reason they were considered by PacifiCorp to be at risk of failure during the summer of 2001.

The six trouble areas were related to construction projects currently underway during the spring of 2001. While an Electric Utility invests in new Capital Projects for various reasons, all of these areas required expansion due to high load growth in their respective service territories. In the construction process, delays were encountered mainly from the aspect of obtaining permits.

The Wasatch Front experienced a 6 percent load growth from the summer of 1999 to the summer of 2000. This is three times the normal load growth PacifiCorp historically experiences. The area electric demand load for the year 2000 was 2,220 MW, with the load increasing approximately 285 MW. Due to the load growth, $45 million of capital investment was expended in this area. The work included upgrades and new construction for 88 feeders and 27 substations.

The press release was issued, in part, because six of these projects were not expected to be completed by a June 1, 2001 self-imposed deadline. If abnormal system conditions were to occur while PacifiCorp worked on 150 major construction projects and/or above-normal temperatures were to occur, the load level would be higher than normal and currently these areas are operating near their maximum capacity.

The following is a more detailed analysis of each of these construction projects and the reason they experienced delays in completion. It also includes suggested actions that can be taken to mitigate future such incidences.

SANDY: SOUTH TOWNE MALL AREA, COMMERCIAL PARK AND SANDY CITY HALL

Project Description: Install Two New Circuits #16 and #17

Additional feeder capacity was needed to serve new load in the area. The Town Center has underground vaults and redundancy for serving the area.

Reason for Completion Delay

The construction project delay was incurred when obtaining agreement from the City of Sandy to compensate PacifiCorp for a $300,000 contribution toward the installation of the underground feeder circuits. An ordinance passed years ago by the City of Sandy requires new electric distribution and transmission facilities to be built underground. The $300,000 amount constituted payment for the additional cost associated with placing the electric facilities underground rather than overhead. It is considered a contribution to aid underground construction.

In discussion with the Director of the Sandy City Public Utilities, it was stated that this requirement by the City of Sandy has been in place for nearly two decades and they did not agree to the cost assessed by PacifiCorp for this particular underground assessment. A main point of disagreement was the location selected by PacifiCorp for the distribution facility. The City preferred a route traversing undeveloped land. Nevertheless, PacifiCorp decided to expend the additional capital investment for the underground installation along their preferred route, regardless of the lack of compensation from the City of Sandy.

There has historically been considerable resistance on the part of the City of Sandy to pay for underground facility charges based upon the following statements by the Director:

- When seeking support for the acquisition of PacifiCorp, ScottishPower management stated (per Sandy official) that they do not believe additional charge for underground distribution facilities is warranted. The rationale was that the combined capital and maintenance costs between underground and overhead construction, over a 20-year period, were found to be similar.
- PacifiCorp collects the difference in capital costs between overhead and underground facilities under current Utah DPU Commission authority. While this is a standard practice for many electric energy service providers, and approved by Utah State Commissioners, PacifiCorp was the originator of this item when filing their extension rules in the past. Subsequently, as a practice PacifiCorp has requested from the State of Utah, it could waive that rule, if they so desire. In this particular case, the extension rule was waived.

- The majority of residents within the City of Sandy prefer to have the electric facilities placed underground. A poll by PacifiCorp, found the residents would agree to increased rates in order to have the electric distribution and transmission facilities placed underground.
- Upon requesting contribution to aid underground construction, PacifiCorp appears to delay construction of facilities for a considerable timeframe. There were several projects cited by the Director of Sandy City Public Utilities in which construction occurred as late as two years after the initial request. A common electric utility practice is to request payments of this nature prior to commencing construction, however, in this case it only exacerbates the issue. The City of Sandy adamantly refuses to pay in advance of construction.
- Estimates provided by PacifiCorp are not firm. One project was cited that began as an estimated $35,000 contribution, which was approved by the City of Sandy. It was later increased to $51,000 and then increased again to over $65,000. However, further investigation revealed the Customer obtained the original estimate from an outside contractor. That contractor did not have all the information necessary to complete an accurate estimate.
- Inaccurate or extremely high estimates for underground facilities contribute to misunderstandings and contention between parties. An example of this would be the three-mile transmission underground project along 106 South Street. PacifiCorp initially estimated this project to cost $18 million. The City requested the construction of this facility be opened for public bidding. Under this process the cost for completion was $2.4 million; a 70 percent reduction from the estimate PacifiCorp quoted the City of Sandy.
- Sandy City is willing to pay a reasonable and fair differential price between overhead and underground construction.

Resolution

The City of Sandy did not agree to pay the $300,000 contribution. Work commenced however, with no interruptions to electric service resulting in the area due to delays of constructing these two circuits. Circuit #16 was installed on June 21 and circuit #17 was completed on June 28.

Mitigation of Future Such Incidences

Cities passing ordinances which require all electric distribution facilities be placed underground or shielded by landscaping or other visual enhancements should also implement operating processes and procedures by which PacifiCorp could, in a timely manner, plan for expansion. If not currently in place, PacifiCorp might assist the Cities in the creation of such processes and procedures that would lead to more conducive and timely approval of their requests for construction permits.

The City of Sandy's procedures are to assess each request for contribution in aid to underground construction on their own merits. When PacifiCorp makes such request to the City of Sandy, the Director puts forth the issue to upper management for their approval. This procedure has worked well in the past for normal and straightforward improvement projects. However, there appears to be a lack of processes and procedures dealing with requests for contributions the City feels are: (1) unwarranted; (2) too expensive; (3) overbuilt, e.g., in conduit and placed under concrete; and, (4) in the wrong location.

The City of Sandy has not been provided an electric delivery expansion plan for their City. They were informed such information is proprietary in nature. PacifiCorp indicated this was because all municipalities have the ability to decline period renewal of their service franchise. Providing planning documents would effectively be providing free engineering services to such an entity.

PacifiCorp should seek to rectify this situation with its customer for several reasons. The immediate reason is construction permits might be obtained in a timelier fashion. A more long-range reason is deregulation may provide alternate energy options to the City of Sandy, with the current dissatisfaction becoming an impetus to seek energy providers other than PacifiCorp.

The Utah Public Service Commission, at PacifiCorp's request, granted an underground surcharge. However, such charges can be handled in a multitude of ways, such as through special rates for jurisdictional areas requiring underground electrical facilities.

PacifiCorp may mitigate these problems through implementation of various policy and procedural changes. Options available to PacifiCorp would be to:

- Create additional rate schedules that do not require underground facility surcharges;
- Provide more accurate estimates and consider them fixed – not changing them;
- Seek contractor bids for such underground work prior to providing such estimates to the City of Sandy;
- Provide a firm date for construction and explain any construction delays to the Customer; and,
- Provide a high-level, five-year expansion plan to the major customers – a document not considered to contain proprietary information.

OQUIRRH: 8400 SOUTH TO 10900 SOUTH AND 2700 WEST TO 7200 WEST

Project Description: Install One New Circuit #19

A new electric distribution circuit #19 was needed to supply service to the new Junior College being built which added considerable load. The college is still expanding and adding load to this area.

Reason for Completion Delay

The line was delayed because of a right-of-way issue with Kennecott Exploration (www.kennecottexploration.com). Kennecott was the landowner that the distribution circuit was to traverse. To further complicate the issue, they lost the permit request sent to them by PacifiCorp. Traversing a water line further complicated the situation.

As the project was nearing construction, copper wire which was being stored on-site was stolen. However, this action had minimal impact (a few days) on extending the project completion date.

Resolution

The permit was eventually obtained from Kennecott and replacement wire was obtained. Circuit #19 was completed and placed into service on July 27, nearly two months late. No outages attributable to this construction delay occurred.

Mitigation of Future Such Incidences

The permit delay could possibly have been anticipated. Nevertheless, the process for obtaining permits by PacifiCorp should be examined to determine if a permitting process redesign might reduce future project delays of this nature.

No change is suggested for storing construction material on-site. Locating material for construction at the job site is a common industry construction practice, reducing warehousing and shipping expense. Some additional consideration is recommended for additional securing material at remote job site locations.

VINE: 900 EAST TO 1300 EAST AND 4500 SOUTH TO 6600 SOUTH

Project Description: Install a Second Transformer and One New Hammer Circuit #11

This involved a new substation transformer and circuit. The work was necessitated by commercial growth in the Fort Union area, mainly a new shopping center.

Reason for Completion Delay

This project was completed by May 25, prior to June 1, the original deadline.

Resolution

Project was completed within the deadline of June 1.

Mitigation of Future Such Incidences

No comment.

HOGGARD: 5415 SOUTH TO 9000 SOUTH AND 3800 WEST TO 8000 WEST

Project Description: Install One New Circuit #16

An additional feeder circuit was required due to load growth resulting from new residential subdivisions and retail stores. There has been significant growth in the "Jordan Landing" commercial area.

Reason for Completion Delay

The project involved obtaining permits from the State of Utah for crossing a State Highway. At the time, State Department of Transportation (DOT) Engineers were considering expanding the road width, so the permit issuance was delayed.

Resolution

The State of Utah DOT eventually issued the necessary construction permits and this project was completed on June 2, nearly on schedule.

Mitigation of Future Such Incidences

Most State DOT Offices issue one to five-year project lists/descriptions and/or timelines for notification to Utilities that may be impacted by their transportation construction activities. The State of Utah DOT also provides this information.

The State of Utah maintains a website at http://www.dot.state.ut.us/progdev/stip that contains a Statewide Transportation Improvement Program (STIP). This is a five-year program of highway and transit projects for the State of Utah. It's published annually and is a compilation of projects utilizing various federal and state funding programs and includes transportation projects on the state, city, and county highway systems, as well as projects in the National Parks, National Forests, and Indian Reservations. The current document covers planned projects in four regions over a timeframe of from October 1, 2001 to September 30, 2006. The type of information provided on this website is illustrated in Table 4-1 below.

INFORMATION PROVIDED	EXAMPLES OF TYPICAL PROJECTS IN REGION 2		
	A	B	C
County	Salt Lake	Salt Lake	Salt Lake
State Road #	89	172	2148
Project Number	STP-0089(47)312	HPP-0172(2)3	HPP-2148(1)0
Project Location	State Street; 9000 to 6400 South, S L	5600 West; 4100 to 2100 South, S L	Main St Extension; 5600 S to Vine St, S L
Project Begins at Reference Mile Post	312	3	0
Len	3	3	1
Project Concept	Road – Asphalt Pavement Reconstruction	Road - Widen to Four Lanes	Road - New Construction
Total Cost	$523,000	$812,250	$2,933,125
Funding Source	Any Area – Statewide	High Priority Projects	High Priority Projects
Project ID Number	2250	2186	2256
Contractor ID Number	50426	50317	50344
Ref DOT Line Item in Budget	106	89[1]	161[1]

Table 4.1: Type of Information Provided by State of Utah DOT

[1] Funding will carry over into the next year.

The Statewide Transportation Improvement Program is developed through a cooperative process between the Utah Department of Transportation, Metropolitan Planning Organizations, and Federal, City, and County Governments. The program is designed to implement the Long Range Highway Plan; the Transit Plans; short-range needs; and, provide for the preservation of the existing transportation systems within the State.

Arguably, PacifiCorp might have anticipated the permit issuance delay by the State of Utah DOT. It is therefore recommended that PacifiCorp examine and redesign their communication procedures with the State of Utah DOT. The process should include procedures to allow for inevitable DOT Project delays and alternatives as those projects and PacifiCorp's construction projects coincide or are in the same proximity.

SOUTH MOUNTAIN: 12300 SOUTH TO POINT OF THE MOUNTAIN AND 3000 EAST TO I-15 AND POSSIBLY BIG COTTONWOOD CANYON

Project Description: Install One New Circuit #13

This project consisted of the installation of the third feeder circuit #13 from the South Mountain Substation. The project was initiated due to the added load generated from a 6,000-home residential development in the Draper area.

Reason for Completion Delay

The project delay occurred due to extensive permitting negotiations with the City of Draper as to where the feeder would be located.

Resolution

PacifiCorp and the City of Draper eventually agreed upon the feeder circuit location and a permit was issued. Thereupon, the project was completed on June 1, meeting the in-service deadline.

The City of Draper's Ordinance Number 340 deals with the issue of placing electric utility lines underground. It is the intent of the City of Draper to require utility lines be placed underground when new utility lines are installed, when new development is undertaken on property encumbered by existing overhead lines, or when existing utility systems are upgraded or altered to serve a new development.

The cost of placing any utility line underground as required by the City of Draper shall be borne by the development requiring the utility service, and may be a condition of development approval.

The City of Draper established an "Enterprise Fund" for the purpose of converting overhead utility facilities to underground facilities. This was the fund that would supply the additional cost requested for placing Circuit #13 underground. The various amounts estimated by PacifiCorp are shown below in Table 4.2. If the City of Draper trenched and backfilled themselves, the cost was reduced to $50,080.

ITEM	AMOUNT
Total Cost for Project Overhead	$201,657
Total Cost for Project Underground	$354,315
The Difference Between Overhead & Underground	$152,658
Cost for Trenching and Backfill that Draper Could Do	$102,578
Remaining Difference for Underground Cost	$50,080

Table 4.2: Cost Items for Circuit #13 Installation Overhead and Underground

A March 5, 2001 letter from PacifiCorp to the City of Draper recognized more lead-time in requesting such contributions would make it easier for the City to acquire and disburse the funds.

Concluding paragraphs of that letter state:

> *I am well aware of the difficulty that this creates. We were prepared to sit down with the City (of Draper) and go over the growth and the increased infrastructure that needs to be put in place well in advance of when it would actually be done. The unexpected growth in demand last year along the whole Wasatch Front requires that we do the work specified prior to the summer cooling season. This substation work is one of many which needed to be accelerated to be sure of handling energy needs. The load growth didn't come from just new construction but from increasing usage of electricity in the average household.*
>
> *Once we have worked through this issue, I suggest that we organize a meeting with the appropriate people in Draper and at Utah Power to discuss future needs on projections, yours and ours. This will allow us to work through issues and for all of us to address and plan for future needs.*

This response is concurrent with good customer relationship methods. It is assumed that there will be continued meetings between PacifiCorp and the City of Draper to exchange information for planning purposes.

Mitigation of Future Such Incidences

Continued relationship building between PacifiCorp and the local regulatory agencies allow for a better understanding of the needs of each party. Allowing for sufficient lead-time on more sensitive projects would minimize the delays in the future. The City of Draper has moved in a direction of accumulating funds for the express purpose of placing electrical facilities underground. This is being done in other states as well. Southern California Edison is one example of this under Rule 20. This should be considered in all franchised areas that so desire to have electrical facilities placed underground.

RITER: 4400 WEST TO 5600 WEST AND NORTH OF 2100 SOUTH

Project Description: Install a Second Substation Transformer and the Lake Park Circuit #17

This project was required due to load growth. The substation serves a high growth residential housing area. Additionally, the overloaded Centennial Substation serves a warehousing district – Gateway.

Reason for Completion Delay

The delay was caused because the circuit path chosen by PacifiCorp involved traversing a protected wetland area. While a full Environmental Impact Statement was not required, there was considerable analysis involved relative to the wetland area. Ultimately, an Environmental Wetlands permit was required to construct this facility. An additional three to four weeks of work commenced to secure the necessary permit.

Further delay in the project was caused by the telephone company, which damaged PacifiCorp’s underground cable when installing their telephone cable.

Resolution

This project was completed by May 30, prior to the deadline of June 1.

Mitigation of Future Such Incidences

There are circumstances where little choice on circuit routes is available. It is assumed that PacifiCorp strives to minimize exposure to, and avoid traversing, environmentally sensitive areas. Selection of a circuit path in environmentally sensitive areas will require additional time to secure permits. This adds to the cost and effort for all involved.

SUMMARY OF SIX TROUBLE AREAS

PacifiCorp's load forecasting techniques, prior to the summer of 2001, were inadequate for the geographic area along the Wasatch Front of Utah. The communication chain from the field personnel to those in charge of asset management broke down. Load growth was not believed to be as significant as the local field personnel stated. Therefore, an examination of the load forecasting at PacifiCorp is appropriate (see Section 5 of this report).

The substation and distribution construction delay generated a need to acquire approval and payment authorization from local communities in a rather hurried fashion. This resulted in deteriorated customer relationships, as PacifiCorp pressured the Cities for permits to allow them to proceed with construction. There was little time for obtaining a consensus between PacifiCorp and the customer.

5 LOAD FORECASTING ANALYSIS

One significant driver for capital improvements is the electrical load growth; i.e., the electrical demand growth experienced in a particular geographic or regional territory. No one can forecast the future accurately all the time, however some knowledge and skills in forecasting electrical loads is essential to accurately predict the future energy needs within a region of the overall service territory.

With the demand for electricity increasing annually, load forecasting constitutes a large part in maintaining reliability of service to customers and controlling PacifiCorp's capital investment costs. These costs are ultimately reflected in the rates PacifiCorp's customers will face in the future.

Energy and peak demand forecasts are typically made for extended periods of time, matching the extended asset lives of the electric utility's facilities. Due to the capital intensity and long-lived nature of electricity assets, persistent over or under capacity is costly. For a given set of demand conditions, too much capacity results in wasting scarce resources that could have been put to more advantageous uses. Similarly, too little capacity results in consumers not having access to electric energy and capacity even though they are willing to pay prevailing prices.

The ability to conduct accurate load forecasting therefore links directly to PacifiCorp's ability to properly manage their financial investment model. Accurate load forecasts are a primary differentiator between successful and at-risk energy companies due to their ability to avoid undue financial exposure.

Therefore, the purpose of this section is to analyze how PacifiCorp conducts its load forecasting, both in general and specifics. This will include: (a) identifying the type of information gathered, i.e., the source of load data used for load forecasting; (b) determining data ownership, i.e., who maintains the data; and, (c) defining load data modeling tools employed by PacifiCorp.

PacifiCorp recognizes that increased expertise in load forecasting is an essential key skill set. As such, PacifiCorp is continuing to develop and augment their existing skill sets relative to the electrical load forecasting function.

The area in Utah along the Wasatch Front is summer peaking. It takes approximately four years before the winter peak reaches such comparable levels. The winter operating capabilities are much higher due to the lower ambient temperatures, so facility additions are based solely on summer peaking conditions. The only exception to this would be that some localized ski resorts are growing at a fast pace.

The Wasatch front has had a growth rate of four to six percent over the past few years. The increased load is due mostly to residential subdevelopment growth, commercial retail growth, and the replacement of swamp coolers with air-conditioners and heat pumps.

Area Field Engineers who work with the new connect employees gather the load projections. The new connect employees inform the engineers of new housing developments or commercial developments. The field engineers add this load to their load projections. The process of communicating this information seems to be informal.

Customers new to the Service Territory normally deal with the “New Connects Manager.”

Two major growth areas have been found to be: (1) Metro; and, (2) Jordan Valley.

The following is a detailed description of the load forecasting methodology PacifiCorp has been using and how it recently invested in sophisticated load forecasting software and related services. This section concludes with NERC load forecasting information, while not as high as the Utah area, the North American Electric Reliability Council members as a whole, had experienced load growth above that which had been forecasted during the later 1990s.

PAST FORECASTING METHODOLOGY AT PACIFICORP

In the past, the main methodology used by PacifiCorp for forecasting load was linear regression analysis. This method makes the assumption that current load growth will follow past load growth. It allows for a “best fit” curve (usually a straight line, hence the term “linear”) to be created based upon the historical load data, which is then extrapolated into future years. For short-term load forecast needs in a localized area, this has been found to be generally adequate, although inadequate for long term needs. Significantly, this methodology provides no forewarning of periods of abnormal load growth, as it is based solely on historical load data.

To circumvent the shortcomings of linear regression analysis, PacifiCorp also periodically used resources internal to the organization to conduct more comprehensive load forecasting studies. In performing these studies, load data from the Area Field Engineers were used in conjunction with economic and population data from various geographic regions. These generally resulted in being on-target 70 percent to 80 percent of the time, which provided a two to three-year window for construction and budget planning purposes.

Load forecasting is one part of a broad range of activities performed by Area Planners (in the Infrastructure Planning section of Asset Management) and Field

Engineers (who report up through a Field Operations & Maintenance organization). PacifiCorp has divided the total six-state service territory into 45 subtransmission study areas and 236 distribution study areas. Planning responsibilities are coordinated between the Network Planning section (managing subtransmission and substation planning) and the field engineers (managing feeder-level reviews). Scheduling of studies is prioritized according to study area load size (in MW of demand) and rate of growth. All studies, even in low-growth areas, are updated at least once within a five-year planning cycle. The study schedules are reviewed and coordinated closely across distribution, substation, and subtransmission to ensure optimal recommendations for capital expenditures.

At the feeder level, the Distribution Planning Studies completed by field engineers include load projections derived through linear regression analysis.

The load data from substations is entered in a spreadsheet where the load growth is reviewed. The field engineers add any additional known load increases called “block loads.” The block loads are new residential or commercial developments. Figure 5.1 illustrates how load forecasting is typically used as the foundation for all future planning activities.

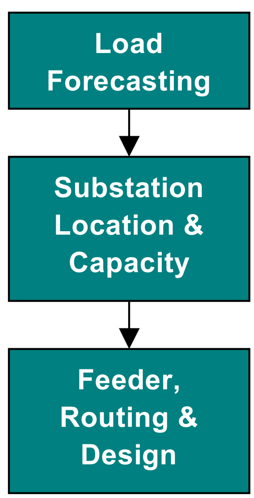

Figure 5.1: Typical Approach to Load Forecasting in Distribution Planning

Load Forecasting Data Collection

Load forecasting at PacifiCorp includes many areas of activity. The broadest forecast is a 10-year, system-wide load forecast, usually prepared annually. This forecast is based on demand data at the substation level (provided by Area Planning Engineers), which is then blended using coincidence factors and rolled up to the transmission level. Econometric data such as population trends, income, and other statistical data are included as factors. This forecast is used for projecting transmission capacity and generation capacity requirements.

Load forecasting is also performed by the Area Planning Engineers in the Network Planning section in Asset Management. This is a five-year load forecast of substation demand. It is used for planning capital improvement projects to support either capacity or reliability requirements at the subtransmission and substation level.

Load forecasting is also performed by Field Engineers. Five-year growth is estimated for each feeder in the distribution study area, incorporating all known information about block load additions and commercial development in the area.

Each of these forecasts has complementary purposes and in some cases may appear contradictory in forecasting conclusions. A system-wide growth rate assumption can be lower, yet compatible, with a higher local growth rate assumption. Scottish Power's Asset Management organizational approach to PacifiCorp more tightly links planning and forecasting functions with capital expenditure controls, as well as more accurate measurement of system performance.

The following is a documentation of information gathered by specific areas relative to data forecasting requirements.

In the recent past, growth rates have been forecasted at a higher rate by the Field Engineers than by the central planning organization in Portland. The higher growth rate in the Utah area has been collaborated in Phase 1 of the ABB load forecasting study. This might likely be indicative of the natural tension between corporate forecasting and cost control measures instituted by a Utility. Increased scrutiny of capital expenditures by upper management initially caused some delays in construction.

Now, consider the manner in which PacifiCorp gathers loading and load forecasting information.

Large Customer Information

Information about loads added by large Commercial and Industrial (C&I) customers is gathered by the Key Account Representatives located throughout the service territory. These employees provide information on new loads to both the Field Engineers and Network Planning Engineers.

Major customers (incurring loads in excess of one megawatt) have "not-to-exceed" contracts that limit their maximum demand to some pre-determined contracted value. Customers incurring less than 400 kW demand are served via load management metering. These efforts are in place as Demand Side

Management (DSM) techniques – initiatives that seek to curtail PacifiCorp's peak electrical demand.

Substation Load Demand Readings

Electric Utilities generally collect load demands either at the distribution feeder level or the total distribution substation on some frequency. If the data is collected manually, it is usually done monthly. When the data is collected through a Utility's SCADA application, it is stored more frequently, as frequent as every 15 minutes. This data is stored for a number of years for load forecasting purposes. PacifiCorp obtains monthly readings from their SCADA application for their major distribution feeders and substations. However, about five percent of the substations require a person to manually read and record the monthly data from demand meters.

The Average Substation Transformer Utilization has historically been running 60 to 80 percent, while PacifiCorp is striving to reach the 80 percent level for all Substation Transformers. The standard substation transformer installed by PacifiCorp is 138-12.5 kV, sized at 30 MVA.

Network planning engineers use the network planning program from Power Technologies Incorporated (PTI), called PSEE. The network planners review the 138, 69 and 46 kV transmission line loading and the transmission and distribution substation loading. There is a separate group that does the planning for the high voltage transmission lines, the 345 and 500 kV lines.

The field engineers provide the forecasting of the loading of the distribution feeders. The majority of distribution is 12.5 kV. There are many other voltages ranging from 4.16 kV to 35 kV. The standard substation transformer size is typically 30 MVA.

Economic Data and Land Use Analysis

PacifiCorp is reviewing the ABB FORESITE computer application for better land use analysis. This information should be available the First Quarter of 2002. This is a change in past practices, i.e., using ABB Foresight for land use studies.

A gap in the "actual load" versus "forecasted load" is evident due to the unexpected load growth along the Wasatch Front. The use of the ABB FORESITE application, currently under investigation, may close this gap. It still needs to be determined whether or not the ABB FORESITE tool will improve forecasting efforts.

The process will be reviewed during 2002. However, no specific review date was identified.

TRADITIONAL FORECASTING DEFICIENCIES

From a more global perspective, consider how the electric utility industry as a whole has encountered load-forecasting difficulties. An Institute of Electric and Electronic Engineering article, "Distribution System Planning in Focus"[1] Ault, Foote, and McDonald discussed many deficiencies in traditional power system planning techniques. The following is a subset of the entire list that focused on the planning deficiencies of greatest relevance to distribution system planning, at least some of which are evident at PacifiCorp. It also provides insight into the far ranging scope of items impacting the load forecasting function as a whole. The comments following each bullet in parenthesis are not those of Ault, Foote, and McDonald.

- Inaccuracies in forecasting cost, construction time, and plant availability can lead to over- or under-planning (there was under-planning in the PacifiCorp situation – not anticipating the need for facilities until it was too late)
- Cogeneration, self-generation, or distributed generation not owned by the host distribution utility nor considered in the original forecast (this is not a problem yet, but distributed generation may well be a large component within the next decade)
- Separation of long-term forecasting activities from ownership and accountability for system operation (note: some regulatory mechanisms exacerbate this problem by introducing uncertainty in utility cost recovery of asset investment dollars – referred to as "stranded assets")
- Loss of faith by decision-makers in computer-based forecasting software (this is being addressed by the ABB FORESITE software planning tool now introduced into PacifiCorp)
- Inability of forecasting techniques to deal with uncertainty despite elaborate sensitivity analysis and risk analysis features (there was nationally an under-forecasting of energy demand during the latter 1990's – see "NERC Load Forecasting" that follows this section)
- Failure to take account of, make use of, and analyze the role of the independent private enterprises in electricity supply (as electric generators in the form of Independent Power Producers (IPPs) enter the market, they may greatly impact the transmission and distribution system)

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[1] Graham W. Ault, Colin E.T. Foote, and James R. McDonald "Distribution System Planning in Focus". The Centre for Electrical Power Engineering, Department of Electronics and Electrical Engineering, Glasgow, U.K., IEEE Power Engineering Review, January 2002.

NERC LOAD FORECASTING

To carry on this perspective of examining the electric industry load forecasting on a national level, consider the analysis performed on the subject matter by the North American Electric Reliability Council (NERC). During the latter half of the 1990s, actual summer peak demand for the United States repeatedly exceeded the NERC aggregated Regional and subregional projections[2].

In addition, the divergence between actual and projected peak demand appeared to increase with time. Figure 5.2 shows the actual and one-year ahead aggregated NERC projection of summer peak demand in the United States for the period 1995 -1999.

The Load Forecasting Working Group (LFWG) and the Reliability Assessment Subcommittee (RAS) also discussed the increasing divergence between aggregated actual and projected demand as a potential risk to future electric system reliability. The LFWG, in conjunction with the RAS, determined there was a need for a detailed study to determine the cause(s) of the demand divergence.

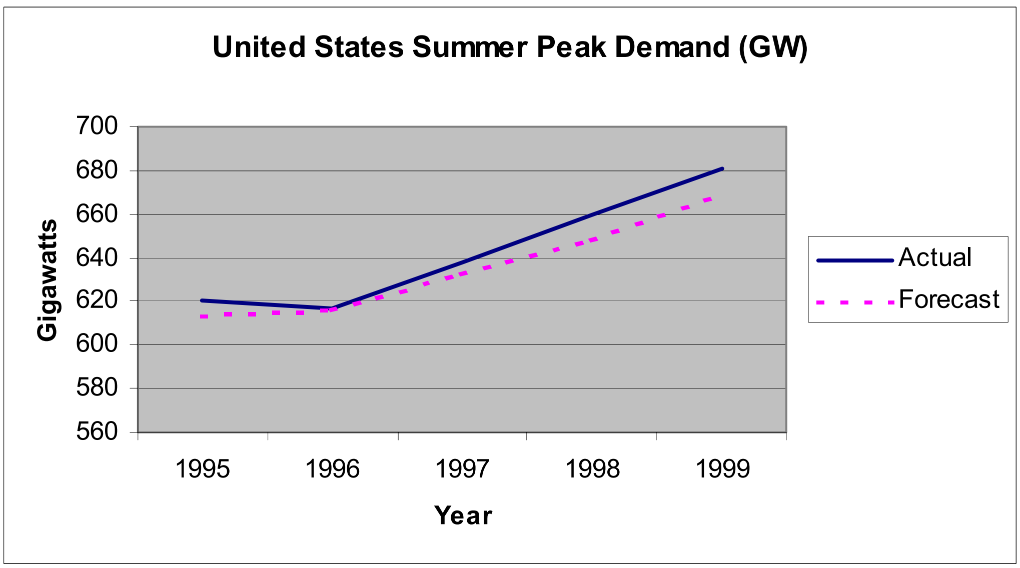

Figure 5.2: United States Summer Peak Demand

Several factors were proposed to account for the divergence between actual and projected peak demand. These factors center on the conditions that typically lead to short-term deviations that cycle above and below long-term trends. First,

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[2] Load Forecasting Working Group of the Planning Committee, North American Electric Reliability Council, June 2001.

weather and temperature variations typically differ from the "normalized"[3] weather assumptions used to develop individual electric utility forecasts. Although "normal" peaking conditions are used to develop these demand forecasts, peaking conditions naturally depend on the presence of global weather patterns that can lead to extreme weather conditions in a Region or subregion. Second, unanticipated economic growth over the short-term can differ from the longer-term economic assumptions used to develop utility forecasts. Strong near-term economic growth can cause substantial, albeit temporary, departures from long-run manufacturing and consumption patterns.

The actual weather patterns can deviate substantially from "normal" weather assumptions used in developing a forecast. Therefore, energy and peak demand information must be weather-normalized. Overall, the combination of abnormal weather and extraordinary economic growth explains the divergence between actual and projected peak demand during the 1995 -1999 period.

Historically, compound annual growth of inflation-adjusted Gross Domestic Product (GDP) in the United States has been three percent over the period 1979 to 1989 and 1989 to 1999. The current forecast of inflation-adjusted GDP in the United States is 2.9 percent over the 2000 to 2010 period. These historical and projected trend growth rates are significantly below the growth experienced during the 1996 to 2000 period. Table 5.1 illustrates the actual historical GDP data.[4]

Year	Inflation-Adjusted GDP Growth
1996	3.6%
1997	4.4%
1998	4.4%
1999	4.2%
2000	5.0%

Table 5.1: United States Historical Gross Domestic Product

[3] "Normalized" temperatures for energy and peak demand projections are usually developed from moving averages over five to 20 years of control area historical data or from 30-year tables provided by the National Oceanic & Atmospheric Administration.

[4] Load Forecasting Working Group of the Planning Committee, North American Electric Reliability Council, June 2001.

From this national perspective we see that while the load growth along the Wasatch Front in Utah was considerably above the national average, the national average was also increasing at a higher growth rate than was anticipated by any of the load-forecasting experts in the US electric industry due to a combination of weather and economic growth.

RECENT IMPROVEMENT IN FORECASTING METHODS

PacifiCorp recognized these types of deficiencies existed within the current load forecasting practices. Therefore, they have recently taken various steps to mitigate the situation. One step was to retain ABB in the Fourth Quarter of 2001 to provide more accurate load forecasting analysis along the Wasatch Front in Utah. ABB will review load forecasting based on land use analysis.

The goal of the ABB forecasting project is to improve the ability to predict when the substations and transmission lines will be loaded to capacity. While the current forecasting allows PacifiCorp to accurately predict when a substation or line will be loaded to capacity two years in advance only about 70 to 80 percent of the time, the new goal is to obtain accurate predictions 90 to 95 percent of the time. How forecasting accuracy is measured is unknown.

The area under study is 60 to 90 miles long by 20 miles wide and includes the area from Ogden to the Spanish Fork. Phase 1 of the two phase proposed study has been completed. The scope of work relative to this effort is included within this section.

A manual Land Use Study was completed five years ago, which ABB referenced as input to their study. ABB uses land use software, ABB FORESITE, to predict the future load growth in the area for the next 20 years. The process involves collecting data from area communities relative to zoning and land use projections. Approximately 70 to 80 percent of the data was be derived from public sources. About 16 of the 51 communities responded to data requests.

Figure 5.3 shows the scope of the Wasatch Front study.

Figure 5.3: Wasatch Front Study Scope

The Scope of Work Assigned to ABB

The following is the “Exhibit A, Scope of Work”, which was extracted (and reproduced with permission) from the PacifiCorp/ABB Contract No. 3000011655. It defines the level of work that ABB will perform for PacifiCorp relative to load forecasting along the Wasatch Front.

Goals

There are three main goals for this project:

- A forecast of electric load growth in the Wasatch Front area, suitable as a base for comprehensive T&D expansion planning, performed using FORESITE software.
- Understanding on the part of PacifiCorp of the forecast, the spatial forecasting methodology, and the data requirements.
- Establish a base for future T&D planning and analysis of equipment loading criteria.

Resources and Results

ABB understands that PacifiCorp has limited resources it can devote to support this project or provide assistance to the ABB project team. Minimizing the “maintenance” that PacifiCorp has to provide to ABB while doing this work will be a priority. ABB also recognizes that PacifiCorp needs to and expects to learn a great deal and ultimately have an understanding of long-range spatial forecasting and the capability to apply the necessary tools at the conclusion of this project. While these two requirements seem to run counter to one another, ABB is confident it can perform the project in a way that produces good performance and balances the two priorities to PacifiCorp’s satisfaction.

For purposes of identifying and organizing work effort, the project will be broken into two phases. The proposal submitted with this letter is for work on Phase 1 only.

FORESITE™ Spatial Load Forecast

Phase 1 – Base Forecast Scenario

Task 1 – Spatial Database Development

ABB will work with PacifiCorp engineers and planners to gather the appropriate geographic data required for populate[*ing*] the FORESITE database. Both internal and external data sources will be utilized to develop a land use and electrical load database with sufficient detail for spatial load forecasting. ABB will leverage a PacifiCorp 30-year planning study done for this area in 1993.

Product: A FORESITE spatial land use database of the Wasatch Front Region, which is approximately 60 miles north to south and includes Ogden to the north, Salt Lake City, and areas south to Orem. Land uses will be classified according to standard FORESITE practices. Electrical load data will be calibrated to the most recent substation level peak demands and weather adjusted to a consistent planning level.

Task 2 – Forecast Set-up and Scenario Definition

Working with PacifiCorp personnel, ABB will identify the load growth scenario to be analyzed.

Product: Definition of base forecast scenario, documented and defined within the FORESITE software model.

Task 3 – Forecast

The ABB project team will perform forecast using FORESITE software with the data collected and assembled in Tasks 1 and 2. Working with PacifiCorp engineers and planners familiar with the area, we will evaluate the resultant forecast scenarios and make necessary adjustments until the results meet appropriate tests of reasonableness and consistency.

Product: Base forecast for the study area, in FORESITE. Load forecast results will be reported by substation for forecast years 1, 3, 5, 10, 15, and 20. Paper and a brief presentation of results will be provided to PacifiCorp.

Phase 2 – Analysis of Alternate Scenarios and Reporting

We highly recommend pursuing Phase 2 to maximize the benefit of FORESITE spatial forecasting. PacifiCorp may want to consider expanding the scope to include additional analysis as well.

Task 1 – Alternate Scenarios

Working with PacifiCorp staff, two additional forecast scenarios representing different global and/or spatial factors will be identified and modeled in FORESITE.

Product: Two additional forecast scenarios, documented and modeled in FORESITE.

Task 2 – Presentation of Results

Results of the forecast, along with a review of the effort, procedure, and issues dealt with during the forecast, will be documented and presented to PacifiCorp staff. The resulting FORESITE database will be delivered to PacifiCorp for future updates and for use in developing T&D plans. A detailed description of the process and methodology used will be documented in a report.

Product: Final report, presentation, and FORESITE database model.

It is anticipated that three on-site meetings with PacifiCorp staff will be required, two in Phase 1 and one in Phase 2. This includes the following:

- Phase 1: Project kick-off, review of available data, identification of additional data requirements, discussion of methodology and the overall approach, definition of the base forecast scenario, and a tour of any areas of concern if deemed necessary.

- Phase 1: Review of forecast and presentation of results, possible discussion of alternate forecast scenarios.
- Phase 2: Final presentation of results and discussion of methodology, technology transfer.

Results of the ABB Load Forecasting Study – Phase 1

Phase 1 of the ABB Load Forecasting Study for PacifiCorp was completed in early March 2002. The decision to move on to Phase 2 is pending. Phase 1 provided one scenario to be used as the base spatial model for further analysis. The following information was provided by ABB as results of Phase 1 deliverables achieved.

- ABB was contracted (Phase 1) by PacifiCorp to create a base scenario model in FORESITE, an ABB spatial load-forecasting tool. This has been completed.
- The project utilized four PacifiCorp personnel in the Salt Lake City area as local experts in for their understanding as to which areas were anticipated to grow the most.
- These PacifiCorp employees, while aiding data collection, were not trained in the operation of FORESITE.
- The Wasatch Front Regional Planning Area provided the bulk of land use information for the study; however, additional information was pulled from approximately fifty different public sources. Econometric data for the regional forecast was obtained from the Utah Governor's State Planning and Budget Office, the US Census Bureau, and other public and private sources.
- In the event PacifiCorp proceeds to Phase 2 of the ABB Proposal, they could use the existing data as a training tool for their employees to build upon.
- Generally, the local Salt Lake City PacifiCorp employees believed there existed a higher growth rate than the central corporate forecasters in Portland.
- General indications of future growth are forecasted between 4.5 percent and 5.5 percent for three to five years, dropping down slightly until the ten-year mark, after which a 2.5 percent growth is forecasted for the remaining ten years.
- The Olympic construction in the past few years has driven growth rates above the 5.5 percent rate. However, it will continue to remain higher than the national average due to conversion of swamp coolers to central air conditioners.

Figure 5.4 provides an overview of the land use analysis that formed the basis of the Wasatch Front study.

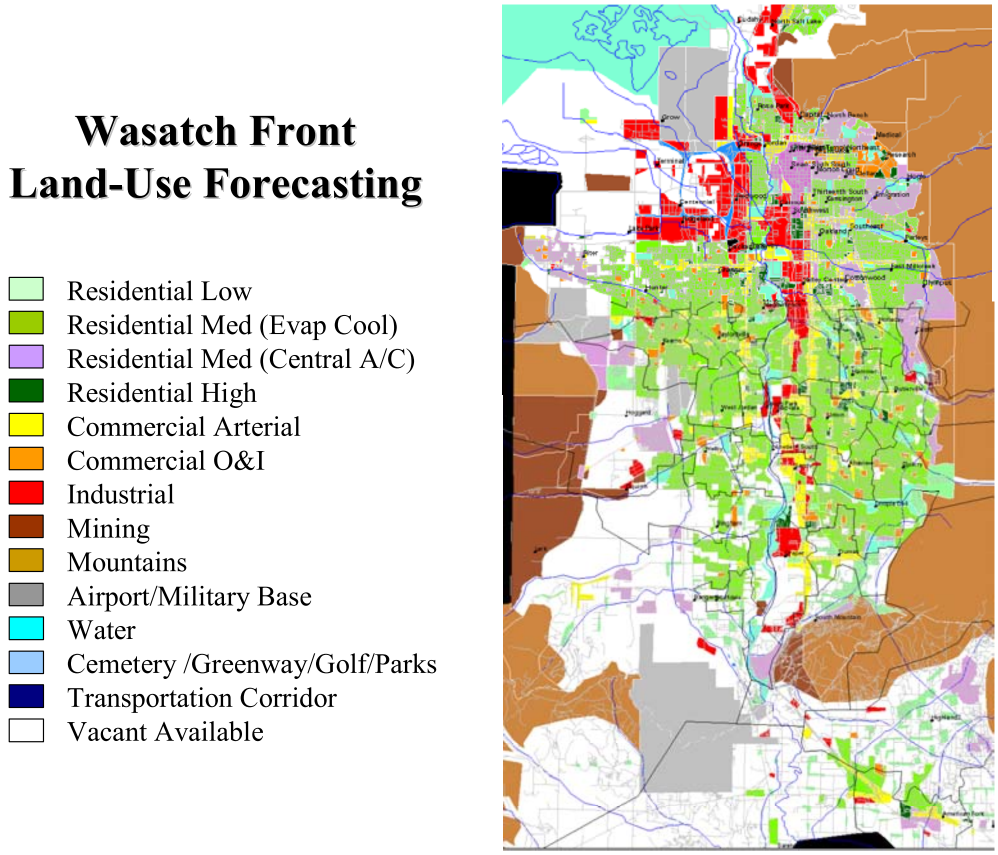


Figure 5.4: Wasatch Front Land Use Forecast

RECOMMENDATIONS

Load growth along the Wasatch Front has been growing at a higher than anticipated rate. Reflecting this fact, although not as high a load growth as in Utah, the national electric load growth has also been growing faster than the experts have been forecasting.

Past deficiencies in load forecasting at PacifiCorp are being addressed by taking steps toward more sophisticated planning methods. PacifiCorp has completed Phase 1 of a load-forecasting project with ABB. This has provided the initial model for which future criteria for load analysis may be conducted. However, the model can quickly become out of date and unusable for forecasting purposes unless further steps are taken to ensure its continued use.

There is a risk associated with increasing substation utilization factors that will be discussed in the next section in more detail. The Salt River Project reportedly has increased the utilization level too high and received customer complaints.

As the average substation utilization level is increased, the load-forecasting accuracy becomes a critical element in the mix. It must be very accurate if high substation utilization is to be maintained. A large unanticipated load growth in one year, at high utilization rates can require significant capital asset investment dollars. Therefore, the following recommendations are submitted:

Continue to Improve Load-Forecasting Abilities

Continue with the current direction of improving load-forecasting abilities. This can be accomplished by either expanding on their current ABB forecasting base or by assuming the function in-house within PacifiCorp.

If PacifiCorp personnel perform this function, training will be required on the use of the ABB FORESITE load-forecasting tool and the associated skill sets for data collection to ensure current efforts are not lost.

There are alternative methodologies that might correspondingly be employed to lead to similar accuracies in load forecasting. The most recent discussions with PacifiCorp centered on the creation of an information data warehouse that would contain load data gathered from the field. The information would be collected, stored and assimilated into other applications for growth and load projection purposes. This information, in conjunction with more end-use research to determine saturation metrics (particularly as they apply to residential air conditioners) would also include weather-sensitive relationships.

An additional effort introduced by PacifiCorp is a community information program. This will effectively create the promotion of a planning partnership between PacifiCorp and local communities. The purpose is to present PacifiCorp's Wasatch Front growth projections to the public for feedback and validation. It will create a stronger link between the economic forecasting used by Wasatch Front communities and PacifiCorp planning activities. This should eventually lead to more accurate load forecasting information for planning purposes and increase the regional and community planning accuracies.

Establish Load Forecasting Benchmarks

Establish benchmarking criteria to determine how closely load forecasts are matching to actual loads. This is the only manner in which it can be known whether or not the load forecasting accuracy is improving. It will be necessary to track this on a winter and summer basis, with most consideration given to the summer peak loading conditions. "Actual" versus "Forecasted" loads should be monitored by geographic sectors as defined by PacifiCorp on a semi-annual basis.

This information might be presented and explained to the DPU Staff rather than issued via a written report. The reason for this method is that there are many variables that constitute a load "forecast." Additionally, there are many variables that impact the "actual" load level attained. Through public discussions, mitigating the impact of these various variables might be achieved.

6 DISTRIBUTION PLANNING

The planning process uses the information from the load forecast as one of the key elements in determining the required changes in the electric infrastructure to serve the load in a reliable and cost effective manner. The distribution planning process involves the optimal sizing of facilities, the optimal timing of additions and changes to the facilities, and the review of the life cycle costs and reliability of alternative plans. Aging of the existing plant is considered here, as are deficiencies inherent in some products that cause early replacement. This later element was typically a concern with the introduction of some underground distribution cables in earlier years.

The goal of the planning process is to ensure the availability of adequate transmission, substation, and feeder capacity to serve the load during normal conditions and outage contingencies. The process involves reviewing alternative plans to improve conditions related to capacity, voltage, or reliability. Alternative plans are required to ensure the plan selected is the least costly plan over the life of the project. Other factors considered are reliability, losses, and future plans.

The major challenge for PacifCorp in the Wasatch Front is providing sufficient capacity in the transmission, substation, and feeders due to the higher than average load growth. The planning solutions implemented in the Wasatch Front include increasing the capacity of transmission lines by converting the voltage of the existing line to a higher voltage, increasing the capacity of substations by adding new transformers to existing substations or installing new substations, and by installing new feeders from substations or feeder ties between adjacent substations.

The purpose of this section is to determine how distribution projects are developed after the initial need has been identified by either load growth or facility degradation through age or obsolescence. The segments involved in this process encompass: (1) the organizational structure that has responsibility of distribution planning; (2) some general planning observations; (3) the asset management group's policies and connection procedures; (4) PacifiCorp's outage restoration standards; (5) their computer modeling tools; (6) how PacifiCorp conducts transmission planning; and (7) the resulting projects planned for implementation. This section concludes with a discussion relative to Southern California Edison's Underground Rule Number 20.

ORGANIZATIONAL STRUCTURE

The following organizational diagram illustrates the management chain of authority from the Executive Vice President through to the Director of Infrastructure Planning. This is a subset of the Asset Management organization of Alec Burden.

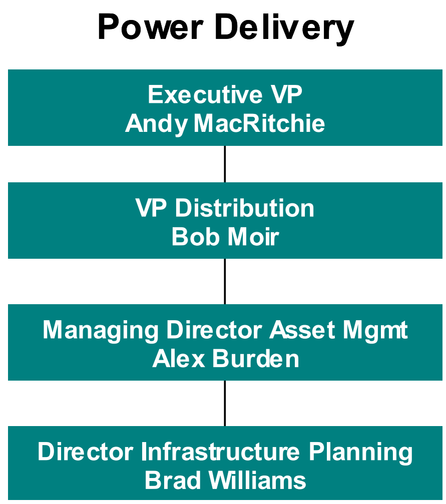


Figure 6.1: Power Delivery Organization

The Infrastructure Planning Department consists of two planning functions, investment planning and utilization planning described below.

Investment Planning

The primary focus of the Investment Planning section is to develop and maintain Distribution's overall capital plans and annual budgets. This group is charged with maintaining strong interfaces with the various planning groups within Asset Management to assess and prioritize future needs for capital expenditure. Additional interfaces with groups outside Asset Management (e.g. new connections forecasts, company load forecasts, regulatory changes) are maintained to monitor the drivers of capital expenditure.

An additional function of the Investment Planning section is the performance of post-construction business case audits. These audits are performed on large projects as well as a sample of smaller projects, to ensure that previously authorized business case benefits claimed have occurred. These benefits might include loss savings, O&M savings, new revenue, or system loading relief. These audits are not intended to replace other audits currently performed by other groups for other purposes.

Utilization Planning

The primary function of the Utilization Planning section is to provide detailed planning for capital asset needs for the existing T&D system assigned to Distribution. Capital asset needs include capitalized replacements, functional upgrades, and mandated relocations or other public accommodations. Capital asset needs are planned in the form of specific projects or collections of continuing projects called investment programs.

The Utilization Planning section also facilitates project and program authorizations for their areas of planning responsibility. In addition, the Utilization Planning section provides a report to company management on asset condition, utilization, or functionality issues on an annual basis.

GENERAL PLANNING OBSERVATIONS

Field engineers and network planning engineers at PacifiCorp review the substation load data every six months. The field engineers do the feeder planning and a five-year load projection on the feeders. There are ten field engineers in Utah. These individuals review the voltage and power factor of feeders. The power factor goal is to achieve a power factor of 0.95 (or 95 percent) on all feeders. The field engineers use ABB FEEDER-ALL for load flow, fault current, and power factor studies. The forecasting data they develop is forwarded to the network planning engineers.

The field engineers model the feeder and use the load flow program to predict the voltage during peak loading conditions. If the model shows low voltage, the field engineer will set a voltage recorder (METROSONICS PA9) to measure the voltage in the field. PacifiCorp has about 500 AMR units (ITRON - telephone-based) and some electronic C&I meters that record voltages. This data is used to verify the results of the feeder studies.

The performance goals of the Field Engineer position are included later in this section, as this is a key position in the planning process.

The network planning engineers review the loading on the transformers and transmission lines. The planning studies are prioritized by load growth. The higher load growth areas receive more attention.

The planning criteria for transmission lines is an “N-1 criteria,” or first contingency criteria. This means the majority of substations have “loop feed” transmission lines so any one line can be removed from service without causing outages. Some of the substations do not have a loop feed due to the length of transmission lines or the size of the substation. This occurs in rural areas where the cost to provide a second transmission source is very high.

ASSET MANAGEMENT’S SYSTEM IMPROVEMENT POLICIES

The Asset Management Department has issued a series of policies that outline the approval criteria under which funds will be released for replacing or upgrading certain devices. There’s significant value in the issuance of such policies and is a prime indicator that PacifiCorp is a mature and efficient engineering planning organization. The Asset Management Department:

- Allows new personnel to quickly understand their responsibilities;
- Assures the field personnel that there exists sound justification for actions from management – as the replacement criteria is uniquely specified; and
- Provides financial forecasting of future anticipated expenditures – the five-year forecast is estimated

Numerous policies have been issued by the Asset Management Department for use within the organization in justifying the replacement of devices, i.e., assets. These might be due to known faulty equipment issued from the Vendor, it may be due to age, or it may be due to some other known deficiencies. Additionally, these policies explain how to operate under storm and casualty situations. Typical policy subject matter includes, but is not limited to:

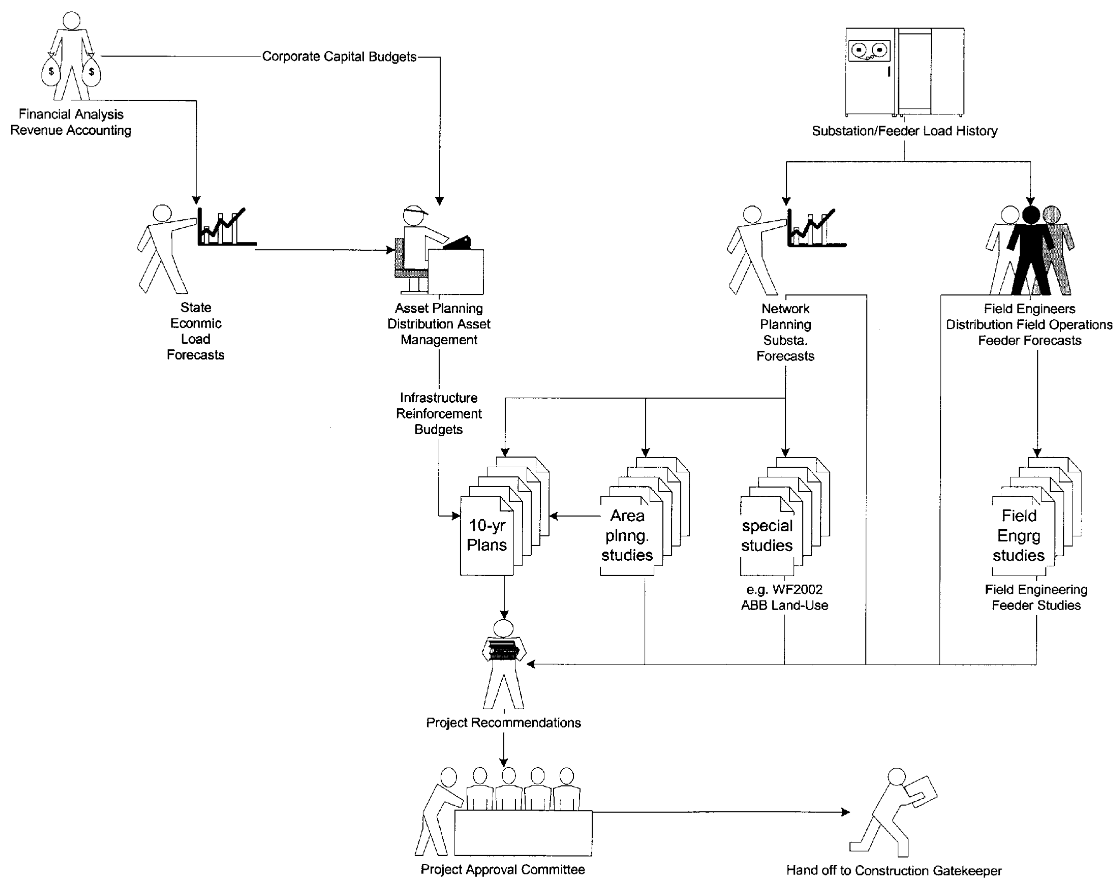
- Storm and Casualty Expenditure Policy
- Type U Busing Replacement Program
- Substation Circuit Breaker Replacement Program Specific
- Transformer Load Tap Changer Program
- Substation Battery and Battery Charger Replacement Program

Each of these asset expenditure policies follows the same eight-step structured format, which in itself is a standard. The eight elements included in each policy are as follows.

- Program – Title (Short Description)
- Investment Reason – Coded Title (Longer Description)
- Description of Asset – Describes what this policy covers
- Asset Replacement Drivers – Describes why devices are replaced
- Asset Replacement Philosophy – Describes the strategy behind the policy
- Asset Replacement Criteria – The hurdles to clear for obtaining funding
- Asset Data Discussion – Backup data supporting action
- Program Funding Projections – Estimated five-year funding requirements

The overall process that PacifiCorp uses for asset improvement is shown in Figure 6.2 below. This methodology allows for input from many information sources, and approval from management, prior to moving a project to the construction stage.

Figure 6.2: PacifiCorp Infrastructure Reinforcement Project Planning Process Diagram



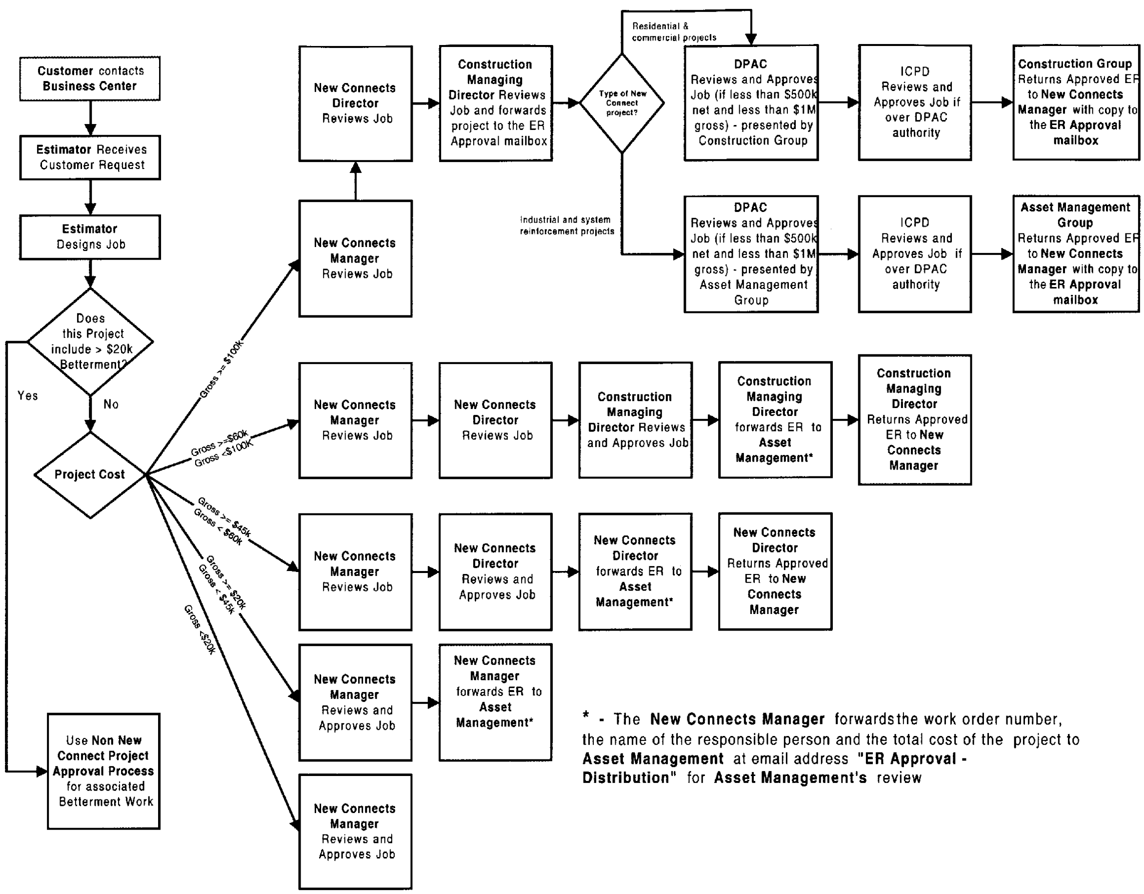
ASSET MANAGEMENT'S SERVICE CONNECTION PROCEDURES

There are two basic types of service installations, new connects and non-new connects (field or internally initiated projects). PacifiCorp has established procedures for serving both. The following is a summary of the procedures, which are included in detail in the Appendix A.

Providing Service to "New Connects"

The process of installing facilities to serve new customers is called "new connects" and is shown in Figure 6.3 below. The "Project Cost" is the key element used to determine the process path that will be taken for providing electrical service to the customer. Note that there may be associated "betterment" work in providing service to the new customer.

Figure 6.3: PacifiCorp's New Connect Process



The estimator creates the job and provides a brief explanation of the project being proposed. This includes the estimated kW load, estimated annual revenue, any special requirements, and the specific tariff applied.

All system reinforcement or betterment jobs associated with New Connect jobs follow Non-New Connect Field Operations Initiated Project process. System reinforcement or betterment projects are those jobs that are intended to increase the capacity of the circuit or substation, reduce the voltage drop on the circuit and/or improve the system reliability. These jobs include, but are not limited to circuit reconductoring, substation upgrades, the installation of line regulators, etc.

The Field Engineer provides supporting studies, historical performance data, economic justifications, etc. to support this additional work. The request for the additional work is submitted to Asset Management with the detailed support information, however detailed estimates on reinforcement or betterment projects are not prepared until approval from Asset Management has been received.

Non-New Connect - Field Operations Initiated Projects

There's also a procedure outlined for processing jobs that are needed for the betterment of the system. These second type of jobs are called Non-New Connect projects. The procedure is defined as follows.

The Field Operations personnel identify the need for a job and prepares the necessary paperwork, which includes an approximate cost. All non-revenue capital projects greater than or equal to $20k need to be submitted to Asset Management for approval. Detailed estimates are generated later. A description of the asset, purpose and necessity, risk assessment, customer contributions, and alternatives evaluated are submitted in order for Asset Management to properly review and approve the proposed project. See Figure 6.4, which illustrates Non-New Connect projects.

It is relevant to understand the submittal includes a complete explanation of why the project is being proposed. This includes engineering studies supporting the project, actual voltage and amperage readings on the equipment, outage history, outage indices (SAIDI, SAIFI, etc.), anticipated outage index improvements from the project, economic justifications and whether or not it has been approved in the current year's budget.

It also includes the risk assessment and alternatives evaluated, the potential consequences of not completing the project both to the system and financially, as well as the probability of those consequences occurring.

Asset Management initially reviews the job for sufficient information (purpose and necessity, etc.) to make an approval decision. It is then forwarded to either Field Operations or Construction for preparing the detailed estimate. For those jobs that do not require a detailed estimate, Field Operations may proceed with construction.

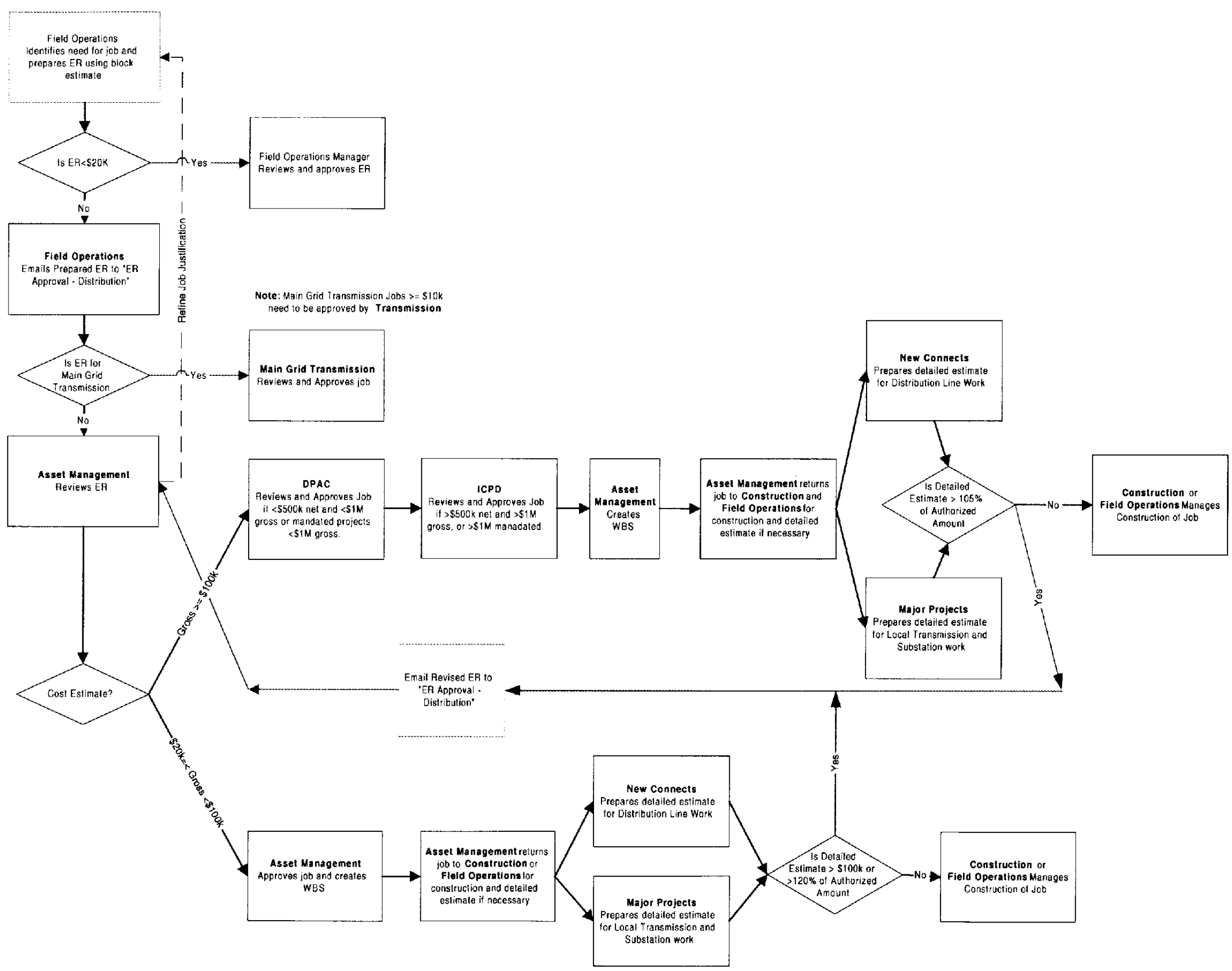


Figure 6.4: Non-New Connect - Field Operations Initiated Projects

Field Engineers

The Field Engineering position at PacifiCorp is directly linked with the planning and design function. Therefore the performance goals are included here to better understand this key position. The duties performed by the Field Engineer are driven by the weighted performance goals that have been established for this position. They are as follows:

- Distribution Studies (5 to 15 percent). Perform studies as needed; meet with appropriate management to discuss study areas and progress on studies; schedule proposed projects and establish measurements as needed.

- Review and Update Load Forecast (three to seven percent). Prepare and maintain a "Detailed Load Forecast Sheet" on each substation and feeder; publish twice annually.
- Capital and Maintenance Budgeting (5 to 15 percent). Maintain a Construction Forecast in DPAD; provide support for budgeting processes of large New Capacity Capital items; and provide engineering and budgeting support for certain routine maintenance programs.
- Field Engineering Corporate Efforts (three to ten percent). Participate in accomplishing corporate requests and goals; attend periodic training.
- System Reliability (three to ten percent). Review feeder performance levels; review distribution relay settings for adjustment; review outage and incident reports; and perform fuse coordination.
- Operations Staff Functions (5 to 15 percent). Attend one safety meeting per month; provide engineering support and perspective as needed.
- Switching Procedures (Variable). Provide switching procedures as needed to facilitate line work.
- Power Quality Trouble Shooting (two to six percent). Provide engineering support in investigations; interpret voltage recorder readings; and support power quality and maintenance on PacifiCorp's electrical system.
- Construction Audit (two to four percent). Perform "as-built" audits as requested.

OUTAGE RESTORATION STANDARDS

So far, we've discussed the organizational structure that deals with Infrastructure Planning at PacifiCorp. This is the group responsible for the asset management function. The system improvement policies were outlined – showing how aged or faulty equipment is justified for replacement. There was also a discussion regarding the procedures for serving both New Connects and Non-New Connects and finally the performance goals of a key position, the Field Engineer was highlighted to show it is tied closely to the following of policies and procedures as defined by Asset Management.

These all serve to show that processes are well established at PacifiCorp for not only serving new customers, but maintaining service to the existing customer base.

Let's look more closely now at maintaining service to the existing customers. Here we require plans on how load will be served under outage contingencies. We'll begin with the mobile substations and spare transformers used as a strategy for restoring power to customers.

Mobile Substations for Load Restoration

Mobile substations are used in two situations: (1) load restoration for loss of a substation transformer or other major substation component; or, (2) during construction projects to serve load while substation components are being replaced or modified. PacifiCorp similarly uses spare transformers, however, these can replace only the substation transformer. They will be included in the discussion regarding Mobile Substations.

The planning criteria for providing service when a substation is out of service is to install a mobile transformer for backup if the load can't be transferred to adjacent circuits. During 70 to 80 percent of the time a substation transformer can be removed from service and the load can be served from adjacent substations. This is not always possible during the summer when the outside temperatures reach high levels, causing a higher than average load on the substations and feeders. The mobile transformers are located throughout the system so any substation transformer outage can be restored in 14 hours or less.

The "PacifiCorp Spare and Mobile Distribution Substation Transformer Utilization Analysis" study of the Asset Management Department presented an evaluation of the current condition of distribution substation transformer spare and mobile backup capability. It provided for the development and implementation of a strategy to ensure adequate backup capabilities in the future and to optimize the use of spare equipment currently available.

This study focuses on the following distribution substation voltage classes: 230-34.5 kV 138-12.5 kV 115-20.8 kV 115-12.5 kV, 69-25 kV, 69-20.8 kV, 69-12.5 kV and 46-12.5 kV, as these voltage classes constitute over 90 percent of the current installed distribution substation capacity.

In summary, the following guidelines for use of spare and mobile transformers have been established:

Spare Transformers are to be available and used for the following applications:

- Replacement of a failed transformer
- Support of construction activities
- Short-term spot overload situations when there are no other options
- Provide equipment to projects where sufficient lead-time to obtain new materials is not available

Mobile Transformers are to be available and used for the following applications:

- Planned transformer and LTC maintenance
- Emergency response to transformer failure and operational problems

- Support of construction activities and overload situations - *only* when other suitable emergency response equipment is available

There are approximately five substations for which the distance to the nearest mobile transformer exceeds the recommendations of Asset Management. They are too remote. There also exist approximately 60 substations for which no mobile transformer of the correct voltage is available. However, about 50 of them are either small single-phase stations or have their own redundancy built in.

The contingency criteria established is as follows:

- Substations with more than seven MVA of load or 2,000 customers will have designated mobile and spare transformers
- Exceptions will be allowed for as many as 2.5 percent of substations where the nearest mobile is greater than 14 hours away

So, in summary, there are mobile substations for most, but not all substations. Furthermore, outage durations of greater than 14 hours may occur in as many as 2.5 percent of all substations.

It should be noted that Salt River Project personnel viewed outage durations of 14 hours as being excessive in relation to their system configuration. Their outage restoration plans do not allow for such a long duration outage, however their service territory is not as rural as that of PacifiCorp. Additionally, PacifiCorp has many more radial feeders that do not have the capability to transfer load to adjacent substations. More information regarding Salt River Project can be found in “Section 8 – Benchmarking.”

Metropolitan and Urban Areas

The downtown areas of Portland and Salt Lake City have networks with redundant substation and feeder sources. These areas can have a transformer or feeder outage without interrupting power to customers. There are also some large C&I customers who have paid to have a redundant source of power.

The majority of underground feeders are “loop fed”, meaning there are two sources for the load. This allows crews to do switching to restore power in the event of an outage and isolate the faulted cable so power can be restored. Additionally, PacifiCorp has been studying distribution automation techniques for a portion of the distribution system, which allows for faster service restoration.

COMPUTER MODELING TOOLS

Network planning engineers use the network planning program from Power Technologies Incorporated (PTI), called PSEE. The field engineers use ABB FEEDER-ALL for load flow, fault current, and power factor studies.

TRANSMISSION SYSTEM PLANNING

Now let's consider how engineering plans are developed at PacifiCorp. They usually begin with planning standards. PacifiCorp uses standards, which exist for many different aspects of their business. In some cases, the standards are phased into use over time, as when setting the standard distribution voltages.

PacifiCorp provided a planning study that reviews options to relieve the possible overloading of a substation. The study considers two alternatives to solve the overloading. The options are reviewed for total costs and other factors such as the impact the alternatives have on the loading of the transmission line.

The load forecast is developed using past load growth rates along with the estimated added load for new commercial load. The study reviews the loading of the adjacent substations to determine if additional capacity is available from other substations. In this example, the utilization of the six substations in the area is 96 percent, so new capacity is required. The study provided follows a planning process that results in the review of alternative options, considers loading multiple substations, and uses past growth patterns and expected new growth for a the load forecast.

PacifiCorp conducts studies of its transmission system network according to the "Transmission System Planning Study Guide." These are detailed transmission planning system studies within specific study areas, as defined by the Guide.

Transmission System Planning Study Guide

SCOPE

This study guide provides general guidelines in performing transmission system planning studies including content, format, and review & approval process.

GENERAL

The purpose of the transmission system planning study is to provide a multi-year plan for the development of the transmission and substation systems in a particular area. The plan can be used as a guide in developing construction forecasts, capital budget items, and operating plans.

The study should identify the most practical and economical means of serving existing and future loads while maintaining high quality transmission service to the customers. The PacifiCorp operability and reliability criteria are used as a guide.

STUDY AREA DEFINITIONS

Central Oregon
Clatsop
Dalreed/Arlington/Sherman
Enterprise
Hood River
Montana
Pendleton/Hermiston
Portland
Walla Walla
Wallula
Yakima Valley

**Cache Valley
**East Salt Lake Valley
Honeyville/Malad
**North Ogden
**North Salt Lake
**Park City/Midway
**Salt Lake City /Millcreek
**South Ogden
**Tooele
**West Salt Lake Valley

**Eastern Utah
**Nebo
**Pavant
**Sigurd
**Southeast Utah
**Southwest Utah
**Utah Valley
**Vernal

Coos Bay
Crescent City
Grants Pass
Junction City/Cottage Grove
Klamath Falls
Lakeview/Alturas
Lincoln City
Medford
Roseburg
Southern Oregon 500/230 kV
Willamette Valley
Yreka/Mt. Shasta

Bear Lake
Big Horn
Goshen
Grace
Powder River
Southern Wyoming
Wyoming West

***Indicates Study Areas located in the State of Utah.*

STUDY CONTENT

Signature Sheet

The title page is used as a signature sheet. It contains the study title, years studied, and date completed. It lists the person(s) who prepared the study as well as the person(s) reviewing the study within Area Planning for approval.

Executive Summary

The Executive Summary provides a brief overview of the information contained in the General System Description, System Problems, and Future Requirements sections. The Executive Summary contains the following items:

- Brief description of the study area
- Purpose of the study
- Loads and growth rates
- Significant system problems with recommended solutions

General System Description

The General System Description should provide an overview of the area transmission configuration, load characteristics, and local generation. The following items are included:

- Primary sources to the area
- Other ties to adjacent areas
- Description of major transmission substations
- Description of area transmission configuration
- Reference to the transmission map and one-line
- Local generation
- Peak load and growth rate
- Study scope

Transmission Map

A Geographic map of the area transmission system is included.

Line Ratings

This is in the form of a one-line diagram of the area transmission system. It includes line ratings, line mileages, conductor, switch locations, and simple substation representations. The diagram shows normally open points in the system.

System Problems and Future Requirements

This section is the core of the study. It contains a discussion of each transmission circuit connecting transmission substations in the area. The discussion includes any inadequacies found for normal system operation and for single contingency operation. Inadequacies are quantified in the form of a percent overload or voltage level, with an estimate of the load shedding required to relieve the problem. In addition, the effect of load growth on the system problems should be quantified.

For each inadequacy, possible solutions to the problem are identified. The economic analysis should include the benefit of any loss savings.

If a proposed solution involves a capacitor bank, the percent of voltage rises when switching should be included, in addition to the recommended size.

And, the list goes on, concluding by stating that any locations where Demand-Side Management techniques could defer significant capital investment should be identified. These may include substation capacity increases or transmission projects.

System Loss Savings

Projects, which are justified solely on the basis of loss savings are described here. These are typically capacitor banks. The project description includes total cost. The loss savings in kW capacity and kWh/year energy is listed as well as the Internal Rate of Return for the project.

Recommended Construction Schedule Summary

The Construction Schedule Summary is in the form of a table that lists the recommended construction items by year for each year of the study period. System one-line sketches describing each construction item are included following the Construction Schedule Summary.

Projected Loads

The load projections list summer and winter peak loads for the area by substation. MW, MVAR, and MVA are listed by year for each year of the study period. In addition, the growth rate and power factor for each substation is included. The Area Planning Engineer in cooperation with the Area Engineer typically provides the load projections. The engineer preparing the study works with the Planning Engineer to prepare the load projections.

Equipment Rating

Equipment ratings are listed by substation. At a minimum, transformers and regulators are included. Any capacity problems are indicated.

Fault Interrupting Ratings

The fault interrupting ratings of any fault-interrupting equipment such as breakers, circuit switchers, and fuses should be listed by substation by bus voltage. For each bus, three phase and single line-to-ground fault duties are listed in MVA and kA. Adjacent to the fault duties, substation equipment fault interrupting capabilities are listed. Any over-dutied equipment is indicated.

Switch Requirements - Loop Opening and Line Dropping

The Switch Requirements table includes each line section in the area. The switches or breakers at its terminals, identify each line section. If switches are used only for sectionalizing a dead line at intermediate points between substations, they are not included in the analysis.

To evaluate loop opening and line dropping capability, the line section should be viewed as if it must be removed for maintenance. Based on the values of loop opening arc reach and line dropping amps, the capability of the switch is evaluated. Any operating constraints that result are noted.

Capacitor Banks

This reference table should list all substation capacitor banks in the area. The capacitor bank rating in MVAR and kV are listed. The type of control, settings, and status are also listed.

Outage Summary

The Outage Summary provides a tabulation of the results of the powerflow (N-I) contingency analysis.

The Outage Summary includes each transmission line section, transformer, and transmission capacitor bank in the area. For each system element studied, the initial outage condition is described. This would be a list of the distribution substations that are out prior to sectionalizing. After sectionalizing to isolate the outage, any additional switching required to restore load is described. Following all possible switching to restore load, any remaining deficiencies should be listed. These might include line overloads or low voltage.

Selected Power Flow Base Case Plots

Powerflow plots (study area) for the base cases are included in the report. This would include summer peak and winter peak for the first and last study years, and light load for the first study year.

REVIEW & APPROVAL

The completed study is initially reviewed by Area Planning Engineering. Then, copies of the draft study are distributed, requesting review of the study, and allowing a period of approximately one month for review and comments.

Following approval of the study, the final signed version is distributed to the people listed in the following section. A number of extra copies are filed in the Area Planning files.

The following sections contain some suggestions, which may be helpful in putting together the data required for the study and performing the system analysis.

PRELIMINARY PREPARATION

Identify substations and transmission lines in the study area. System one-lines, data books, geographic maps, past studies, and the Area Planning Engineer can assist in this effort.

Review previous Transmission System Planning Studies for the area if available. Even old studies can be helpful in providing insight into long-range plans for an area.

Review Distribution System Planning Studies for the area. The distribution studies can provide information on loads and load transfers, regulator settings, capacitor banks, small generators, construction plans, and other items which may affect the transmission study.

Tour area substations. There is no better way to clear up discrepancies in equipment records. The tour also provides a feel for the geography of the area, the condition of the equipment, the types of loads, and the potential for load growth.

While visiting a substation, all major equipment nameplate data should be recorded. In addition, control settings, fuse sizes, and load and voltage readings should be taken (to the extent possible). Following are some items to check:

- Transformer MVA, class, available no-load taps, no-load tap settings, connection, and impedance.
- Regulator or LTC control settings, including PT and CT ratios.
- Transformer fuse type and size.
- Breaker or recloser fault interrupting ratings.
- Transmission line switch attachments, if any.
- Capacitor bank number of units, MVAR, and kV ratings.
- Capacitor bank control type and settings, including PT and CT ratios.
- Load and voltage readings.
- Bus configuration, open switches, parallel transformer operation.

SYSTEM ANALYSIS

The powerflow analysis is performed for peak-loading conditions, typically summer and winter at a minimum, performed for the first and last year of the study period. In addition to the peak powerflow cases, a minimum load case is run with the system normal. This case is used to determine whether any system deficiencies (voltage too high) exist at light load. Any recommended tap or control changes are evaluated at both peak load and light load.

A load duration curve should be obtained for the area from the dispatching system in Salt Lake or from the Power Statistics group in Portland. The load duration curve is used to determine the minimum load level for an area (typically 20-30 percent). It is also used to determine the area load factor (typically 40-70 percent). From the load factor, a loss factor for the area is obtained. They are typically related as follows:

$$\text{loss factor} = (\text{load factor})^{1.9}$$

If desired, a more accurate estimate of loss factor is obtained by analyzing the hourly load data. The loss factor is used to estimate annual MWh loss savings for a project or operational recommendation:

annual MWh loss savings = (peak MW loss savings) x (loss factor) x (8760 hours)

The load level used for the powerflow analysis is typically the non-coincidental substation peak loads multiplied by a factor to account for the diversity in substation peaks. A typical factor would be in the range 90-100 percent.

The powerflow analysis should include both system normal and N-1 contingency operation. For contingency analysis, each system element should be removed from service one at a time.

In addition to the contingency analysis, capacitor switching analysis is performed. For each substation capacitor bank, the powerflow model is used to determine the percent voltage change for switching.

The powerflow model is also used to perform line switching analysis. For loop opening operations, the voltage peak magnitude and angle on each side of the open switch are used to get an estimate of recovery voltage across the switch as it opens.

For capacitor switching, the PacifiCorp guideline for voltage fluctuation is based on the frequency of switching:

- Capacitors which are switched regularly 3.0%
- Capacitors which are switched seasonally 4.5%
- Capacitors which are only switched during emergencies for voltage support 6.0%

Examples of Transmission System Planning Studies

To include a complete transmission system planning study would add significant bulk, but not serve as well as the executive summaries of three typical transmission system studies. These studies are presented for understanding the scope of investigation conducted at PacifiCorp. These summaries give much insight into the nature and form of PacifiCorp's methodology. Note these are extracted from the original document.

Executive Summary #1 - "North Ogden Area Transmission System Study (2001-2006)"

The focus of the study is the 138kV and 46 kV transmission system including transmission and distribution substations in the North Ogden area. The purpose of the study is to identify system constraints and local reinforcements needed to meet area load growth for the period from winter 2001-02 to summer 2006.

Load in the study area is projected to peak at 343 MW during the summer of 2002 and is projected to peak at 271 MW during the winter of 2001-02. Based on historical load growth data, the overall area load growth is approximately 5.5 percent for summer and 6.3 percent for winter.

The most significant system deficiencies identified in the study include the following:

Steady State Equipment Overloads

With current load projections the North Ogden Area is projected to experience several transformer overloads during the summer of 2002. See pages 10-11 for specific transformer loading. PacifiCorp plans to relieve the worst equipment overloads in the North Ogden Area before peak summer 2002 loading conditions. Plan to replace two overloaded 7 MVA transformers, one at Box Elder and one at Pleasant View with 14 MVA units. Recommend replacing the Pleasant View unit by the spring of 2001 and replace the Box Elder unit by the spring of 2002.

To further relieve transformer and 46 kV line overloads, PacifiCorp plans to construct two new 138-12.5 kV substations and rebuild 9.1 miles of overloaded 46 kV line. The new substations (East Bench, Midland) will allow load transfers to occur to reduce the most significant equipment overloads in the area for the summer of 2002. However, a third 138-12.5 kV substation (BDO) may be required to serve load at BDO for the summer of 2002 depending on actual summer 2001 peak loads and other block load additions in the area.

With current load projections, during the summer of 2003 the North Ogden Area will again experience 46 kV line overloads, transformer overloads, and marginal 46 kV voltage levels. See pages 12-13 for a list of projected equipment overloads.

Recommend converting five 46-12.5 kV substations (2nd Street, Pioneer, Lincoln, 23rd Street, Marriott) to 138-12.5 kV (30 MVA) substations to relieve equipment overloads in the North Ogden Area. Also recommend building two new 138-12.5 kV (30 MVA) substations (Plain City, Cold Water Canyon) and adding a second 138-12.5 kV transformer at West Ogden to relieve projected equipment overloads through summer of 2006.

With current load projections the North Ogden system is going to require the system improvements outlined in the study to serve PacifiCorp's normal steady state system load throughout the study period. Due to the rapid growth experienced in the North Ogden Area, recommend that system loads be monitored to detect any significant changes in the forecasted load levels. Significant changes in load will necessitate changes in the time line of the construction table found on pages 18-19.

Executive Summary #2 - "Salt Lake Valley East & West Area Transmission System Study (1999-2004)"

The focus of the study is the 138 kV and 46 kV transmission system including transmission and distribution substations in the Salt Lake Valley East & West Area. The purpose of the study is to identify system constraints and local reinforcements needed to meet area load growth.

2004 summer load for the study area is projected to peak at 1,675 MW coincidental for a normal summer. The overall valley including Park City and Tooele is projected to peak at 2,598 MW. The 2003-2004 winter load is projected at 1,528 MW for the study area, and 2,466 MW for the overall valley including Park City and Tooele. The average annual load growth is approximately 4.4 percent for summer and 4.1 percent for winter over the 5-year study period. This is based on historical load growth and does not include block load additions. Based on recent history, the growth could go as high as 6 percent. The overall load factor for the study area is 65 percent.

The planning for this system covers two portions. One is the ongoing growth in the distribution load with the associated distribution substation improvements. This requires on average 80 MVA of capacity to be added each year to the system. To maintain 95 percent power factor on the system, about 20 MVAR of capacitors is needed each year on the 12.5 kV system. Because much of the system is under 95 percent power factor, the study shows a larger initial installation of capacitors.

The second portion of the area planning is ensuring that the underlying transmission system is capable of supporting the projected loads. These improvements are in larger capacity blocks, and as such occur on an infrequent basis. For instance, a new 448 MVA 345-138 kV transformer is needed every three or four years. A new 138 kV transmission line with 250 MVA of capacity is needed every two or three years.

An additional problem encountered is the sagging voltage on the main backbone transmission system. As the loads increase, the power factor necessary to maintain adequate voltage in the Salt Lake Valley increases as well. Towards the end of the study period all load growth must occur at close to unity power factor.

System problems and recommended system improvements are identified in the study.

Executive Summary #3 - "Utah Valley Area Transmission System Study (1999-2003)"

This study focuses on the 138 kV and 46 kV transmission system including transmission and distribution substations in the Utah Valley Area. The area south of the Spanish Fork substation within Utah Valley is discussed in the Nebo Area study. The purpose of the study is to identify system constraints and local reinforcements needed to meet area load growth for the period from 1999 summer through the 2003-04 winter.

Electrical load growth in the Utah Valley is high. The summer growth rate for the valley is 5.2 percent and the winter growth is 5.6 percent. For Provo and North the growth is approximately 7.5 percent in the summer. The 1999 summer load for the study area is projected to peak at approximately 537 MW and the 1999-00 winter load is projected to be 511 MW. The power factor for the valley's load is about 88 percent for the summer peak and improves to 96-97 percent during the winter peak. The overall load factor for the area is 59 percent.

The more significant system deficiencies identified in the study include the following:

Normal Steady-State System – Line/Transformer Overloads and Low Voltage Concerns

Under normal steady-state conditions (no line or transformer outages) before the end of the study period, the Utah Valley Area will experience line and transformer overloads as well as voltage problems on the sub-transmission system during peak load. In addition distribution voltages will also sag. To raise voltage, the study recommends installation of 46 kV capacitor banks at Highland and Timp and a 138 kV capacitor bank at Spanish Fork. To alleviate the line and transformer overloads, the study recommends construction of the Tri City Switch rack, upgrading the American Fork and Pleasant Grove substations to 138-12.5 kV substations, installation of a 46-12.5 kV transformer at Willowridge, a second 46-12.5 kV transformer at Vineyard and transformer capacity upgrades at Pelican Point and Mapleton.

Poor Power Factor During the Summer Peak

The overall power factor of the load in Utah Valley is low even after the addition of capacitor banks on the distribution lines and at the distribution substations over the years. During the summers of 1997 and of 1998 the power factors were between 87 percent and 91 percent on the 138 kV system. The power factor during the winter peak is substantially better at 97 percent.

There are 102 MVARs of installed capacitor banks in the Utah Valley substations. A 12 MVAR 46 kV capacitor bank is recommended for the Highland 138-46 kV substation in 1999. A 46 kV 12 MVAR cap bank at Timp substation has been proposed in previous budget cycles. This should be included in the 2000 budget cycle. Also a 100 MVAR 138 kV cap bank is recommended in 1999 at Spanish Fork.

Provo City and Lehi City loads have poor power factors during the summer peaks (89 percent). This results in low 138 kV bus voltages at Hale and Highland (96 percent). It is recommended that work begin with Provo City and Lehi City to enforce contract obligations for improved power factor and encourage them and remind them that it is in their own interest as well as ours to maintain adequate power factors during the summer peak.

Line Overloading with the Loss of the Timp-Spanish Fork 138 kV line

The proposed reconductoring of 2.5 miles of the Hale – Cherrywood 138 kV line from 477 ACSR to 1272 ACSR will eliminate the line overloading in this section on the loss of the Timp-Spanish Fork 138 kV line in 2002.

The Loss of the Hale 138-12.5 kV Transformer or the Loss of the Timp 138-46 kV Transformer

With the loss of either the Hale or the Timp 138-46 kV transformers the other transformer will overload during summer peak periods. By the last year of the study up to 37 MW of load shedding is required to restore service to the area through the remaining transformer. We recommend moving the Hale 138-46 kV transformer to the Timp substation as a second transformer and replacing the Hale transformer with 150 MVA 138-46 kV transformer in 2003.

The Loss of the Orem-Willowridge 46 kV Line or the Loss of the Willowridge-Hale 46 kV Line

With the loss of either of these lines closing 46A at Sharon provides additional voltage support that is needed. In 2002 and 2003 with 46A at Sharon being closed the Timp Tap-Sharon 46 kV line overloads to 111 percent and 116 percent respectively of its normal summer rating. Reconductoring 2.7 miles of the Timp

Tap-Sharon 46 kV line from 397.5 ACSR to 795 ACSR in 2002 is recommended to relieve the line overload.

Fault Interruption Capabilities and Line Switching Concerns

Fault duty is within the capability of the equipment in the study area. Line charging currents were within the limits of the switch capability. Attachments exist where excessive recovery voltage during loop opening results or alternative procedures are available.

Capacity Increases Outside the Five-Year Horizon

Because of the rapid growth in the area, looking just outside the time horizon of this study, a capacity upgrade should be considered for the Northridge 46-12.5 kV substation, a second transformer at Lindon substation, new 138-12.5 kV substations at sites in Alpine and Battle Creek and at the Spanish Fork substation. Consideration and studies for a 345 kV source at Tri City are recommended within the ten-year horizon.

PROJECTS IMPLEMENTED AT PACIFICORP

PacifiCorp reports that all Wasatch Front Subtransmission and Substation Projects that were submitted, were approved. These approved projects are shown below in Table 6.1.

Project Description	ISD[1]	Total Cost
Terminal #2 - Inst 138/12.5 (30) Transformer	Jun-02	$2,600,000
Rose Park #2 incr cap and 4 to 12kV conv.	Jun-02	$1,250,000
El Monte-Uintah 46kV Line Rebuild 5.6 Miles	Jun-02	$2,600,000
LonePeak #1 New 138/12 Sub (118thSo & 1-15)	Jun-02	$3,125,000
Clinton - Install 2nd Transformer	Jun-02	$2,500,000
Midland - New 138/12.5 kV (30 MVA) Substation	Jun-02	$4,100,000
Grantsville Sub- 46/12.5kV (10.5MVA) Cap Incr	Oct-02	$ 400,000
Quarry-DimpleDell 138 kV Loop-Phase2 (3 mi)	Jun-02	$2,870,000
Box Elder Sub - 46/12.5 Cap Inc	Jun-02	$ 800,000
Butlerville #4 138-12.5 kV	Jun-02	$2,850,000
90thSouth 345-138 #3&#4 Incr Cap	Jun-03	$8,263,000
MidValley-Cottonwood 138k #2 (5.5 mi)	Jun-03	$6,010,000
East Bench - Inc Cap, Convert to 12.5kV	Jun-02	$4,700,000
Capitol Sub-Incr Capacity 46/12.5	Jun-02	$ 140,000
Tri-City Sub - Inst. 138-12.5 (30) Transformer	Jun-02	$2,095,000
Angel Sub - Inst. 138-12.5 (30) Transformer	Jun-02	$2,400,000
Taylorsville-Kearns-WestValley 138kV Phase I	Jun-03	$2,055,000

Table 6.1: Approved Wasatch Front Subtransmission & Substation Projects for 2002 & 2003

[1] ISD = In-Service-Date

Some of the feeder projects were not approved, but not due to budget constraints. In fact, PacifiCorp was about $2.6M over budget on distribution feeder capacity projects company-wide. If feeder projects were not approved, it was because they did not have sufficient justification.

For example, a planned development did not materialize, or lower cost options were approved instead (such as phase balancing and adding fixed caps instead of adding voltage regulators). Budget constraints exist, but it apparently does not limit approvals for construction of required projects. However, these budget constraints do add additional scrutiny. PacifiCorp insists that all projects having demonstrated actual need have received approval, regardless of budget status.

Table 6.2 lists the Feeder Projects that were approved along the Wasatch Front in Utah for completion in 2002.

Project Description	ISD	Total Cost
BDO Backbone on Depot Drive	03/01/02	$137,378
Pioneer #11 Reconductor #2 ST	05/01/02	$147,000
Vineyard 11 New Circuit	05/01/02	$210,000
Highland 15 Rebuild 800 E Alpine	05/01/02	$130,000
Kearns 12 Load Relief	05/01/02	$ 24,000
Stansbury #12 Reconductor 4000N	06/01/02	$426,000
Syracuse Substation New Circuit #15	06/01/02	$105,000
East Layton Extend #13 Feeder	06/01/02	$350,000
Draper #12 Tithing Hill Reconductor	06/01/02	$ 30,000
90th South 11 UG	06/01/02	$ 76,000
Bangerter #17 Install Regulator Bank	06/01/02	$ 50,000
Hoggard 12 Regulator Bank FY2003	06/01/02	$ 49,000
Taylorsville 14 Unitized Switch FY02	06/01/02	$ 6,500

Table 6.2: Listing of Utah Feeder Projects for 2002 In-Service Dates

Finally, these improvement projects are communicated to management in several ways, but one is in a pictorial form that shows substation loadings before and after the improvement projects are completed. Figure 6.5 is a “Before” diagram of substations loading in the Ogden area. All substations depicted in green are 80 percent or less loaded. Those in yellow are loaded from between 81 percent and 99 percent. Those loaded 100 percent or higher are shown in red.

Similarly, Figure 6.6 is an “After” diagram of the same Ogden area. In this case we see a considerable reduction in the number of substations depicted in red. Those that do remain in red are only slightly over 100 percent loading on peak.

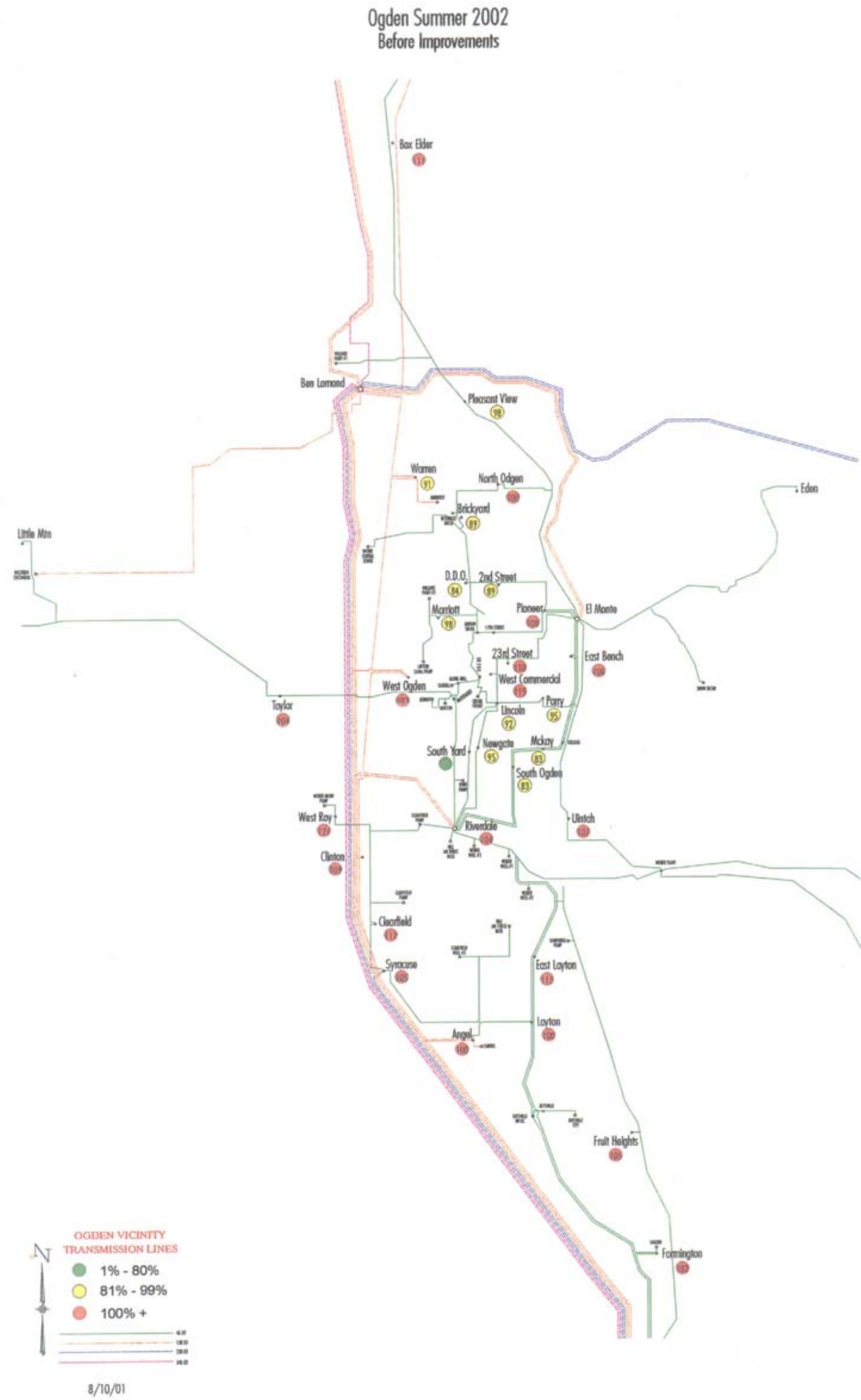


Figure 6.5: Substation Loading in Ogden Area Before Improvements – Summer 2002

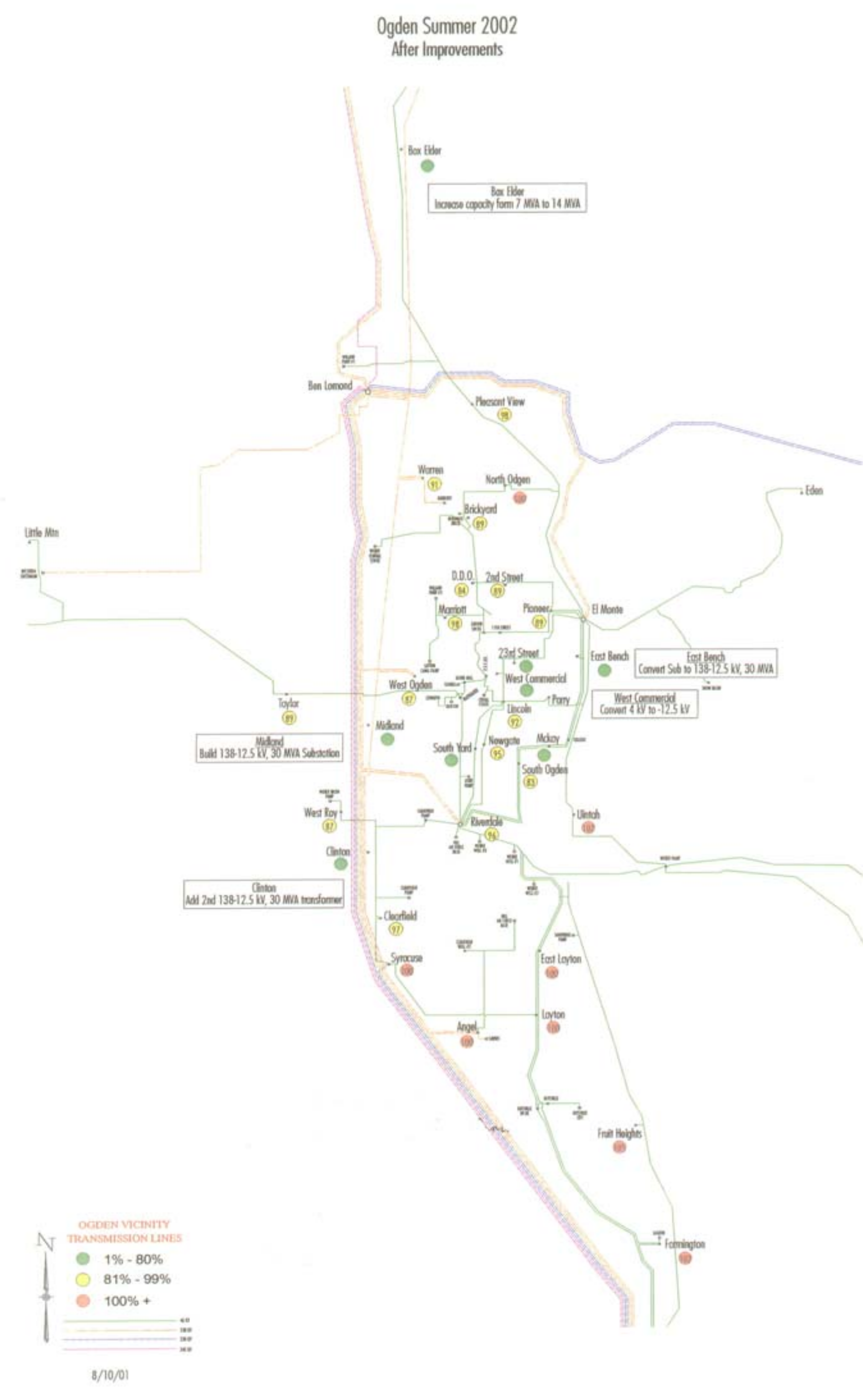


Figure 6.6: Substation Loading in Ogden Area After Improvements – Summer 2002

SOUTHERN CALIFORNIA EDISON'S UNDERGROUND RULE NUMBER 20

There is one additional item that should be covered under the planning section, as it has to do with the asset management function. The discussion centers around the cost of underground versus overhead, for the benefit of PacifiCorp's constituents. This subject was addressed by Southern California Edison (SCE) and the State of California and is detailed in SCE's Underground Rule Number 20. The actual State Statute is clear for upgrades or specific city requests on existing lines, but unclear for new lines required for load growth. The City of Sandy, and likely others, want all Utah customers to pay for their UG benefit. In the situation with the City of Draper, funds have been allocated for PacifiCorp to underground certain feeders not allocated to Developers.

The UG Surcharge California allows utilities to collect upfront money from customers to apply toward UG projects requested by a community based on the amount of funds available that has been allocated to the community. Details of Rule 20 follow.

SCE Rule 20

A. SCE will, at their own expense, replace its existing overhead electric facilities with underground electric facilities along public streets and roads, and on public lands and private property across which rights-of-way satisfactory to SCE have been obtained by SCE, provided that:

1. The governing body of the city or county in which such electric facilities are and will be located has:

a. Determined, after consultation with SCE and after holding public hearings on the subject, that such undergrounding is in the general public interest for one or more of the following reasons:

(1) Such undergrounding will avoid or eliminate an unusually heavy concentration of overhead electric facilities;

(2) The street or road or right-of-way is extensively used by the general public and carries a heavy volume of pedestrian or vehicular traffic; and

(3) The street, road, or right-of-way adjoins or passes through a civic area or public recreation area or an area of unusual scenic interest to the general public.

b. Adopted an ordinance creating an underground district in the area in which both the existing and new facilities are and will be located requiring, among other things,

   (1) that all existing overhead communication and electric distribution facilities in such district shall be removed,

   (2) that each property served from such electric overhead facilities shall have installed in accordance with SCE's rules for underground service, all electrical facility changes on the premises necessary to receive service from the underground facilities of SCE as soon as it is available, and

   (3) authorizing SCE to discontinue its overhead service.

2. SCE's total annual budgeted amount for undergrounding within any city or the unincorporated area of any county shall be allocated as follows:

a. The amount allocated to each city and county in 1990 shall be the highest of:

   (1) The amount allocated to the City or County in 1989, which amount shall be allocated in the same ratio that the number of overhead meters in such city or unincorporated area of any county bears to the total system overhead meters; or

   (2) The amount the City or County would receive if SCE's total annual budgeted amount for undergrounding provided in 1989 were allocated in the same ratio that the number of overhead meters in each city or the unincorporated area of each county bears to the total system overhead meters based on the latest count of overhead meters available prior to establishing the 1990 allocations; or

   (3) The amount the City or County would receive if SCE's total annual budgeted amount for undergrounding provided in 1989 were allocated as follows:

      a. Fifty percent of the budgeted amount allocated in the same ratio that the number of overhead meters in any city or the unincorporated area of any county bears to the total system overhead meters; and

      b. Fifty percent of the budgeted amount allocated in the same ratio that the total number of meters in any city or the unincorporated area of any county bears to the total system meters.

b. Except as provided in Section 2.c., the amount allocated for undergrounding within any city or the unincorporated area of any county in 1991 and later years shall use the amount actually allocated to the city or county in 1990 as the base, and any changes from the 1990 level in SCE's total annual budgeted amount for undergrounding shall be allocated to individual cities and counties as follows:

   (1) Fifty percent of the change from the 1990 total budgeted amount shall be allocated in the same ratio that the number of overhead meters in any city or unincorporated area of any county bears to the total system overhead meters.

   (2) Fifty percent of the change from the 1990 total budgeted amount shall be allocated in the same ratio that the total number of meters in any city of the unincorporated area of any county bears to the total system meters.

c. When a city incorporates, resulting in a transfer of utility meters from the unincorporated area of a county to the city, there shall be a permanent transfer of a prorata portion of the county's 1990 allocation base referred to in Section 2.b. to the city. The amount transferred shall be determined:

   (1) Fifty percent based on the ratio that the number of overhead meters in the city bears to the total system overhead meters; and

   (2) Fifty percent based on the ratio that the total number of meters in the city bears to the total system meters. When territory is annexed to an existing city, it shall be the responsibility of the city and county affected, in consultation with SCE serving the territory, to agree upon an amount of the 1990 allocation base that will be transferred from the county to the city, and thereafter to jointly notify SCE in writing.

d. However, Section 2.a, b, and c, shall not apply to any utility where the total amount available for allocation under Rule 20-A is equal to or greater than 1.5 times the previous year's statewide average on a per customer basis. In such cases, SCE's total annual budgeted amount for undergrounding within any city or the unincorporated area of any county shall be allocated in the same ratio that the number of overhead meters in the city or unincorporated area of any county bears to the total system overhead meters.

e. The amounts allocated in accordance with Section 2.a, b, c, or d, may be exceeded where SCE establishes that additional participation on a project is warranted. Such allocated amount may be carried over for a reasonable period of time in communities with active undergrounding programs. In order to qualify as a community with an active undergrounding program, the governing body must have adopted an ordinance or ordinances creating an underground district and/or districts as set forth in Section A.1.b. of this Rule. Where there is a carryover, SCE has the right to set, as determined by its capability, reasonable limits on the rate of performance of the work to be financed by the funds carried over. When amounts are not expended or carried over for the community to which they are initially allocated, they shall be assigned when additional participation on a project is warranted or be reallocated to communities with active undergrounding programs.

3. The undergrounding extends for a minimum distance of one block or 600 feet, whichever is less. Upon request of the governing body, SCE will pay for the existing allocation of that entity for:

a. The installation of no more than 100 feet of each customer's underground electric service lateral occasioned by the undergrounding, and/or

b. The conversion of a customer’s meter panel to accept underground service occasioned by the undergrounding, excluding permit fees. SCE or the governing body may establish a lesser allowance, or may otherwise limit the amount of money to be expended on a single customer's electric service, or the total amount to be expended on all electric service installations in a particular project.

B. In circumstances other than those covered by A. above, SCE will replace its existing overhead electric facilities with underground electric facilities along public streets and roads or other locations mutually agreed upon when requested by an applicant or applicants when all of the following conditions are met:

1. a. All property owners served from the overhead facilities to be removed first agree in writing to have the wiring changes made on their premises so that service may be furnished from the underground distribution system in accordance with SCE’s rules and that SCE may discontinue its overhead service upon completion of the underground facilities, or

b. Suitable legislation is in effect requiring such necessary wiring changes to be made and authorizing SCE to discontinue its overhead service.

2. The applicant has:

a. Furnished and installed the pads and vaults for transformers and associated equipment, conduits, ducts, boxes, pole bases and performed other work related to structures and substructures including breaking of pavement, trenching, backfilling, and repaving required in connection with the installation of the underground system, all in accordance with SCE's specifications, or in lieu thereof, paid SCE to do so;

b. Transferred ownership of such facilities, in good condition, to SCE; and

c. Paid a nonrefundable sum equal to the excess, if any, of the estimated costs, including transformers, meters, and services, of completing the underground system and building a new equivalent overhead system.

3. The area to be undergrounded includes both sides of a street for at least one block or 600 feet, whichever is less, and all existing overhead communication and electric distribution facilities within the area will be removed.

C. In circumstances other than those covered by A or B above, when mutually agreed upon by SCE and an applicant, overhead electric facilities may be replaced with underground electric facilities, provided the applicant requesting the change pays, in advance, a non-refundable sum equal to the estimated cost of the underground facilities less the estimated net salvage value and depreciation of the replaced overhead facilities. Underground services will be installed and maintained as provided in SCE's rules applicable thereto.

D. The term "underground electric system" means an electric system with all wires installed underground, except those wires in surface mounted equipment enclosures.

IMPROVEMENT RECOMMENDATIONS FROM WALLACE TECHNOLOGY MANAGEMENT LTD

PacifiCorp had contracted *Wallace Technology Management Ltd* to provide the following recommendations and actions regarding planning. These recommendations are currently being implemented at PacifiCorp. The list of recommendations is provided below and meets with high concurrence.

- Monitor substation utilization trends to better target investment.
- Establish criteria for enhancing feeder to network design; as dominant land use changes from rural to urban; provide a load transfer capability.
- Intelligence – Build and foster long-term relationships with local planning and development authorities.

- Communications – Initiate formal reporting of feeder growth forecast from Field Engineers to Network Planning.
- Establish joint planning review meetings.

RECOMMENDATIONS

PacifiCorp is a mature electric utility that is moving rapidly toward the restructuring as an asset management driven organization. It has the expertise in conducting planning studies in a methodical manner that ensures needed projects are properly planned and initiated for construction. However, there are some possible recommendations that can be made to promote higher reliability and customer service.

Load Input from Field

While there is a process in place for formal reporting from the Field Engineers to the Asset Management Department, there might be a more proactive reporting of feeder growth from field employees to the Field Engineers. This recommendation could be part of the recommended improvement from Wallace Technology on communications. Justification of projects will not be adequate without load projections from field personnel.

Distribution Automation

PacifiCorp should consider development of a standard for distribution automation and utilize the practice in planning. This involves establishment of a communication protocol, device sensing and control selection, determination of data collected, and economic evaluation of sectors to be automated.

Distribution automation along the Wasatch Front is useful in areas where there are loop feeder capabilities. On radial feeders, there exists no breakdown capability.

Feeder Switching Analysis

PacifiCorp should develop a formal documentation on substation and feeder switching (breakdown) during outage contingencies. These documents should be available to system operations dispatchers to be used to restore power. These documents should be adequately updated and maintained.

The Field Engineers have the most knowledge of the system they oversee. Therefore, PacifiCorp relies on the availability of the Field Engineer for information during outages. However, the Field Engineer may not be available at all times due to vacations and other circumstances that may take the Field Engineer away from the work area.

Review Planning Process

PacifiCorp should review the overall timing involved in the process of planning studies and the timing of the approval of projects. The one planning study reviewed during the interview process of this project showed a possibility that the project would not be completed by the time the overloading of the substation could occur.

PacifiCorp should consider approving the study for new substation capacity additions at least two years prior to the need of the project. The approval date of the study under review was less than one year before the projected overload date of the substation and the projected completion date is one year after the substation could be overloaded.

Reduce Outage Restoration Duration

It is recommended that PacifiCorp review its outage restoration procedures to reduce the planned outage duration to be less than 14 hours maximum. This would increase customer satisfaction. It is understood that this is the worst-case situation, where an outage occurs in the night or on a weekend and the maximum distance from the mobile storage location to the faulted substation must be traversed. Possibly an average outage duration where mobile substations have been installed would indicate a more likely outage duration customers could anticipate.

Many of PacifiCorp's substations are of a radial nature, however as continued growth occurs, it should prove beneficial and economical to loop feeders. This will reduce the dependencies now placed on mobile substations and spare transformers.

Underground Surcharge by Franchise

PacifiCorp should propose, and the DPU should consider authorizing, an Underground surcharge rate for customers within UG franchises such as Sandy and Draper to keep rates and benefits to all customers equitable. Refer to SCE Rule 20.

Cities could establish UG districts allowing PacifiCorp to collect a small surcharge from customers within that city. The City can use these collected funds toward undergrounding existing lines or for paying the difference of UG to OH for new lines going through their UG district. If there is insufficient money in the fund, PacifiCorp might advance or finance the costs to be paid back from the surcharge over some specified period of time.

7 DISTRIBUTION ENGINEERING

This section moves on with the examination of the actual engineering of the field devices. It entails the inventorying of equipment sufficient for construction and maintenance; the field construction processes employed by PacifiCorp; and the load levels and switching criteria under which the distribution system operates on a daily basis.

This section reviews the engineering standards used by PacifiCorp. The engineering standards provide guidelines on equipment loading and utilization, design of substations and feeders, and protection and reliability. The applications of the standards are used in the planning process. For example, a standard used by PacifiCorp is to limit substation transformer loading to 100 percent of nameplate during the summer, so the planning process provides alternatives to reduce the possibility of loading these transformers during normal and emergency conditions.

The engineering standards address reliability issues. These issues include the standards for restoring power by switching or using mobile transformers and the power quality of electric service.

The first and major aspect of the Distribution Engineering area can be found in the PacifiCorp Distribution System Engineering Handbook.

THE DISTRIBUTION SYSTEM ENGINEERING HANDBOOK

The PacifiCorp Engineering Handbook, "1E.3.1 – Distribution System Planning Study Guide" is maintained by the Engineering - Standards and Technical Support Department. The table of contents includes the following information.

As one can readily see, the Engineering Handbook is filled with all the necessary information required for a Distribution Engineer to carry a job from conception through to construction.

For the purpose of this study and in particular as it relates to distribution engineering, consider “Section 7 - System Analysis and Problem Identification.” It contains all the operating criteria under which the equipment might be loaded for differing periods of time. From the Engineering Handbook, one example is presented for review, “Section 7.5 - Equipment Capacities” and the associated “Section 7.5.1 - Substation Transformers.”

7.5 Equipment Capacities

Accurate assessment of distribution equipment capacities is crucial to system planning. Responsibility for this function as it applies to distribution substations overlaps between Distribution Systems Engineering and Area Planning Engineering. Area Planning should always be consulted when the need for a substation equipment upgrade is determined or when equipment ratings are in question.

Meter readings and their corresponding multipliers need to be verified for accuracy before using the data from them in a system study.

Equipment capacities may not be equal to the equipment nameplate. Various factors contribute to this discrepancy such as elevation and ambient temperature, field modifications, previous usage (loading history, through fault history, duty cycle history, maintenance history), and factory defects. Detailed information on loading guidelines can be found in Engineering Handbook 1.B.4 System Reliability Criteria. Listed in 7.5.1 through 8 are various types of equipment with comments on the determination of capacity ratings for each.

7.5.1 Substation Transformers

Substation transformers usually come with from one to four sets of capacity ratings.

Each set of substation class transformer ratings usually includes one rating based on a 55° C and another based on a 65° C rise over ambient temperature for each of the following designations, if applicable:

1. OA or OW (oil air or natural convection cooling using the cooling fins and tank construction of the transformer)
2. FA (forced air or fan-cooled where a single set of fans is mounted on the cooling fins)
3. FOA (second set of fans mounted similar to the first, which allow a significant capacity upgrade above the first set)

4. FOW (forced oil and forced air by means of an oil circulation pump usually mounted near the base of the transformer in addition to the above fans).

Some older transformers lack forced air equipment and most distribution substation transformers lack forced oil capability.

Transformer ratings will affect the capacity rating based on the following factors:

1. Nameplate limitations

   If a transformer nameplate shows only a 55 degree C rating, it should not be assumed that it has a corresponding 65 degree C rating because it may not have been constructed to handle the extra heat transfer. Likewise, if the transformer nameplate shows only OA ratings do not assume that the transformer will have a standard FA, etc. rating.

2. Temperature and altitude considerations

   Substation transformers are designed to operate at certain maximum ambient conditions. Spare substation transformers when placed into service should have their ratings verified for the temperature and altitude of their new location.

3. Determining effective ratings

   Ratings are best determined by consulting the original manufacturer's test data sheets or specifications. If these are not available, provide the manufacturer a serial number and photograph(s) of the unit in question showing cooling equipment and position. Substation Engineering may help locate successors of out-of-business manufacturers to obtain this information. Manufacturers are often able to provide relatively low cost fan kits or other equipment to help upgrade transformer ratings in the field.

4. Paralleling transformers

   If transformers are operated in parallel, their impedances may not be matched. In this situation, the load split must be determined by calculations based on impedance ratios.

5. New transformer sizing

   Transformer sizing is subject to an economic evaluation. Often the economic evaluation will result in a transformer at least two standard ratings larger than the projected peak load. PacifiCorp uses Engineering Handbook I B.4, System Reliability Criteria, as the basis for realize (time to upgrade substation transformer) purposes.

   The engineer should evaluate the following with respect to substation transformer capacity:

a. Physical presence of any specified cooling equipment (before assuming the capacity rating designated on the nameplate) be

b. Altitude of substation

c. Average summer high or winter low ambient temperature at the substation during peak

d. Transformer load or duty cycle

e. Maintenance history

f. Manufacturer's certification of capacity

g. Availability of additional cooling equipment

EQUIPMENT LOADING CRITERIA

Use and Development of Feeder Contingency Studies

Field engineers and network planning engineers review the data on substation loading every six months. The field engineers do the feeder planning and a five-year load projection on the feeders. The field engineers use ABB FEEDER-ALL for load flow to develop contingency studies. They use the results of these studies and work with the dispatcher when providing support to dispatchers and crews during power outages. The contingency studies are used to determine if equipment can be removed from service for a planned outage.

The network planning engineers review the loading on the transformers and transmission lines. The network planning engineers also work with dispatch to determine the best way to restore power during outages and to determine if transmission lines can be removed from service for maintenance.

Switch Placement

The field engineers provide recommendations for the placement of distribution switches. The switches are placed based on information from the studies when reviewing load transfers for contingency planning and when developing the plans for new feeders.

Transformer and Other Equipment Loading Levels Monitored

PacifiCorp has various engineering standards for equipment loading and other engineering standards. The loading standard for substation transformers is a limit of 100 percent of nameplate in the summer and 120 percent of nameplate in the winter. The loading guidelines are based on ANSI C57.92 and assume a pre-loading level of 90 percent.

The loading guideline for distribution transformers is based on ANSI C57. They have a feeder balance standard that allows for a maximum unbalance of 20 percent of the phase currents. The substation feeder standard is a 1200 amp breaker. The load limit is 480 amps to allow for capacity for load transfers and growth. They use 1000 AL underground cable and 795 AL overhead main feeders. The loading standard for the cable is based on the number of cables in a duct.

Many of the substations use SCADA to monitor the loading of equipment. The loading data from substations without SCADA is collected and stored each month. This data is reviewed by field and network planning engineers to develop contingency plans and for long-range planning studies.

Mobile Substation Criteria

Mobile transformers are available for backup in the event of an outage to a substation transformer. The majority of the transformer loads can be served from adjacent feeders or substations for 70 to 80 percent of the time. This is not always the case during the summer when the outside temperatures reach high levels causing higher loads on the substations and feeders. The mobile transformers are located throughout the system so any substation transformer outage can be restored in 14 hours or less.

CONSTRUCTION PROCESS

The new connects group have a one to two-year advance knowledge of many of the large residential and commercial developments. They communicate this to the field engineers. The communication of the information is informal and may not occur in a timely manner in locations where there are not field engineers.

There is some concern at the local field level that the Asset Management group delays projects because they want to wait to make sure the predicted load develops as forecasted. However, the local Utah employees are confident that the Asset Management group will fund the projects once a critical overload condition has been verified.

The “connects” area feels most new connects are completed on time. The material and crews are available to get the work completed. They mentioned only one occasion where a job required a 75 kVA 480/277 volt transformer and the job was delayed because the transformer wasn’t available. There are usually sufficient jobs in progress where the material can be transferred from one job to another to meet deadlines. Many of the projects are delayed due to delays from builders, plumbers, and other crafts.

OPERATIONS AND MAINTENANCE PROCESS

The wires group is primarily an operating and maintenance group. They can do construction projects or allow contractors to do the projects. The wires group installs services, inspects the plant, and does construction work. There are 39 PacifiCorp crew foremen and 25 contract crew foremen in Utah.

The wires managers are responsible for completing the maintenance activities. These activities are a priority. The managers will do construction work if time is available after completing the maintenance work. The asset management group establishes the inspection requirements. The wires manager has some discretion on where to direct some of the activities such as by circuit or substation.

A general inspection is done every two years where the line is patrolled. A detailed inspection is done every eight years where all poles are inspected. The underground is inspected every four years. The poles are tested and treated every 16 years. Utah has 26 inspectors. These are journeyman lineman.

INFORMATION TECHNOLOGY ISSUES

Only two items will be reviewed in regards to Information Technology issues: (1) the use of a Geographic Information System; and, (2) how readily the work management system and the tracking/scheduling software is integrated with SAP.

Use of GIS or Spatial Data

GIS, AutoCAD and ABB FEEDERALL maps are currently used at PacifiCorp. GIS is being implemented with CADOPS, the outage management program. The plan is to have GIS replace the AutoCAD maps and the ABB FEEDER-ALL maps used for feeder planning.

Integration to SAP Information

The designers in the new connects area enter construction projects in an estimating program. They also enter data used for tracking and scheduling the projects, ordering materials, and updating the plant records. SAP is used in the work order cost and estimating system. There is an ongoing effort to coordinate all of the programs to reduce the quantity of data that needs to be entered and updated.

RECOMMENDATIONS

The following recommendations are made in the Distribution Engineering area.

Field Engineer Staffing Levels

While PacifiCorp has centralized many functions (redistributed), it is recommended that PacifiCorp review the staffing level of the designers and field engineers in the areas where the load is growing at a faster than average rate. These positions require at least four years of special training to be proficient in the required skills. PacifiCorp should consider increasing these staffing levels, since the growth is projected to continue at the current rate for the next few years.

In the event PacifiCorp chooses to outsource this function, it will still be necessary to train the outsourced personnel in the processes and procedures currently employed.

Migrate to One GIS Mapping System

PacifiCorp has been moving toward a GIS data centric model whereby spatial and network connectivity attributes reside in one system. The system (FastGate) currently supports PacifiCorp's outage management system (CADOPS) with network connectivity and mapping graphics. The company is moving forward with elimination of redundant data entry and having the FastGate support other business requirements such as map plotting through AutoCAD and various network analysis tools.

It is recommended that PacifiCorp continue to migrate from three mapping systems, GIS, AutoCAD, and ABB FEEDER-ALL to one GIS mapping system. It is understood that PacifiCorp is redoing this entire process, and RCMS (the design estimation tool) will be replaced with a graphical estimation tool.

PacifiCorp should strive to involve the necessary employees in this transition to ensure the GIS mapping system can replace the AutoCAD and FEEDER-ALL maps. Acceptance of new systems by being a part of its creation is a key element to successful implementation.

Provide Tighter Integration into SAP

PacifiCorp should continue to integrate the cost estimating, mapping, and tracking programs into SAP to eliminate the need for the same data to be entered in multiple programs.

CURRENT BENCHMARKING EFFORTS AT PACIFICORP

Transmission Reliability Benchmarking Study

PacifiCorp has participated most years in the “Transmission Reliability Benchmarking Study” conducted annually by SGS Statistical Services, LLC. This benchmarking effort was initiated in the mid-1990's. Last year's benchmarking participants consisted of 30 large utilities, both investor owned and public, which represented 370,000 MW or approximately 50 percent of the total load in the United States. Miles of circuits represented were 270,000, or 14,731 individual lines.

The benchmarking study is a comparison of line reliability statistics by voltage class between companies, as well as within a company. Many different views of the data are provided, such as by mile, or by outage cause, etc. Its intent is to provide participants with information about where they lead or lag the industry. The study statistically drills down into many areas to provide information about where to focus reliability expenditures to gain maximum benefit.

As an example of findings from the most recent study, PacifiCorp's 672 transmission circuits appear to outperform the industry at the lower voltage levels (138 kV and below) and under-perform at the higher voltage levels (345 and 500 kV). Individual circuit statistics indicate those lines with high importance but poor performance. Additional information provided by the benchmarking report segregates the outage causes into nine distinct cause codes, such as trees, lightning, storms, etc.

This information is used to prioritize PacifiCorp’s line maintenance expenditures toward high-importance circuits that under-perform the industry and have associated readily identifiable solutions (e.g., tree trimming, upgraded lightning protection, etc.). A number of “worst performing” transmission circuits identified in last year’s benchmarking received large maintenance expenditures this past year.

BenchmarkingCommunity.com

In 2001, PacifiCorp (Customer Service) purchased a five-year unlimited use license for the Distribution franchise on BenchmarkingCommunity.com from the ePerformance Group. The license entitles the purchaser to unlimited use through 2005, with no additional annual fees. BenchmarkingCommunity.com is an online interactive benchmarking and performance management tool. It was purchased to aid in achieving the goal of PacifiCorp attaining “top-ten status.”

Benchmarking Communities Advisory Team

Purchasing the Distribution area license, automatically put PacifiCorp on the Benchmarking Communities Advisory Team. There are currently five electric utilities represented on the Advisory Team; PacifiCorp, Northeast Utilities, Texas Utilities, North Power (Australia) and Northern Ireland Electric Board. Two additional utilities are currently considering joining at the Advisory Board level. In addition, numerous utilities participate at the subscriber level.

The Advisory Team meets quarterly to develop and debate the scope and content of each of the Distribution modules. The Distribution Franchise will ultimately have 20 modules. Currently the Reliability, Line Maintenance, and Customer Care modules have been developed. The Restoration, Construction, New Service Connects, Contract Management, Supply Chain, Materials Management, Asset Strategy, Vegetation Management, and Planning and Line Design modules are under development.

Being on the Advisory Team enables PacifiCorp to shape each module to obtain maximum benefit from participation. Input can be sought from the entire Distribution business in the development of the modules, achieving a high level of participation. Thus far: Vegetation Management, Construction, Wires, and Procurement have all been included in the process to ensure maximum benefit from PacifiCorp’s participation. All 20 modules should be completed and online in the first quarter of 2002. At that time it will be feasible to start using it to its fullest capacity, including benchmarking performance against peers and networking with best practice companies.

PacifiCorp benefits from its participation in Benchmarking Communities in a number of ways. It enables comparison and ranking against PacifiCorp’s competitors. It will assist in identifying strengths and weaknesses of the organization. It also provides information on what the best performing utilities are doing differently than PacifiCorp. It enables networking with other electric distribution professionals for mutual gain. PacifiCorp views utilizing benchmarking as essential to accomplishing their goal of attaining the position of a top-ten utility and remaining in that position.

Reliability Metrics from ScottishPower Acquisition

As a condition for the ScottishPower acquisition of PacifiCorp, there were certain customer service performances and guarantees agreed to by all parties. These were categorized into three areas: (1) Network Performance; (2) Customer Service Performance; and, (3) Customer Service Guarantees.

PacifiCorp's historical records overstate the actual performance experienced by customers, i.e., performance is worse than the historical data show due to inaccurate measurement and reporting systems. PacifiCorp has made improvements to its outage reporting system through the following general actions:

- Revision of manual reporting procedures, and through implementation of PROSPER, an automated outage reporting framework linked to Computer Aided Distribution Operations (CADOPS)
- Linked customer information to system facilities through their completed Customer Connectivity Project

Figure 8.1 is a graph of the historical number of outages. From this it is clear that automatic outage reporting systems will report a higher number of outages. Automatic reporting is far superior to gathering of actual numerical values. PacifiCorp analyzed the outage data and concluded that all outage causes were reporting higher values, it was not just a weather issue.

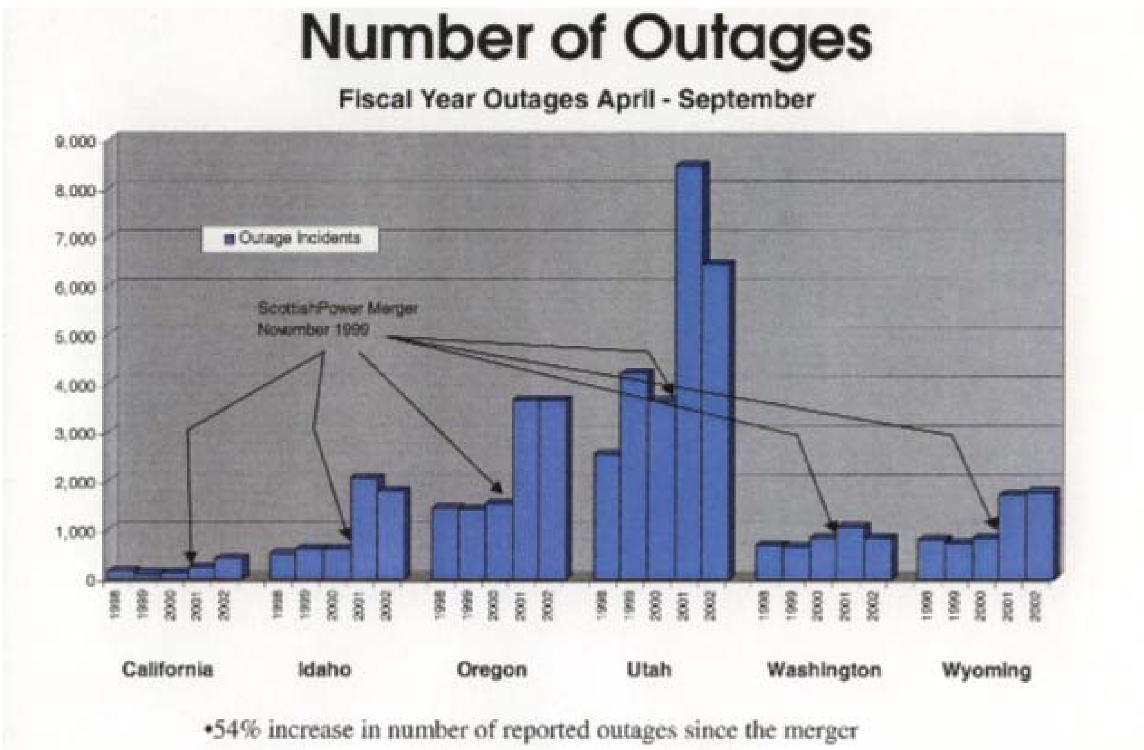


Figure 8.1: Automatic Outage Reporting Increases Number of Outages Reported

In fact, over that same period, their customer satisfaction with reliability of supply increased and the number of trouble calls during the increased outage-reporting period of 1998 through 2001 actually decreased. See Figure 8.2 below.

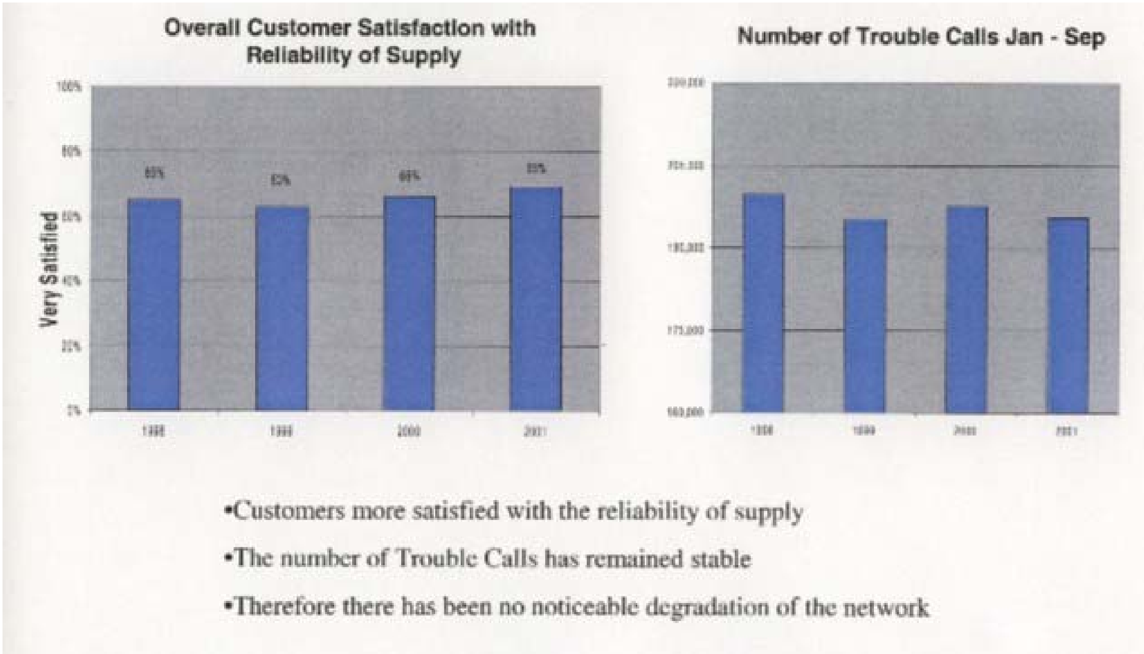


Figure 8.2: Satisfaction Increasing and Trouble Calls Decreasing from 1998 Through 2001

Customer satisfaction increased from a low of 63 percent in 1999 to a high of 69 percent in 2001, after implementing the automated reporting system. Correspondingly, the numbers of trouble calls over that same period decreased from a high of approximately 200,000 in 1998, to a low of approximately 195,000 in 2001. Neither of these metrics reflect actual outages occurring, but rather actual outages being reported more accurately.

Distribution Reliability Metrics

Within the "Network Performance" area there exist five performance commitments made by PacifiCorp to the State of Utah that are relative to this study. They are as follows:

- System Availability – The industry standard metric is "System Average Interruption Duration Index" (SAIDI)
- System Reliability – The industry standard metric is "System Average Interruption Frequency Index" (SAIFI)
- Momentary Interruptions – The industry standard metric is "Momentary Average Interruption Frequency Index" (MAIFI)
- Worst Performing Circuits – A unique PacifiCorp metric is CPI
- Supply Restoration – A PacifiCorp performance standard that commits to restore power to 80 percent of their customers who experience an outage within three hours of initial interruption.

The “Customer Average Interruption Duration Index” (CAIDI) is another industry standard metric used only for internal comparison at PacifiCorp. This is the average time required to restore service to an average customer per sustained interruption. A sustained interruption is defined as any outage lasting two minutes or longer. CAIDI equals the sum of all customer interruption durations divided by the total number of customer interruptions.

$$\text{CAIDI} = \frac{\text{Sum of all Customer Interruption Durations}}{\text{Total Number of Customer Interruptions}}$$

PacifiCorp measures this metric in minutes of all customer interruption durations divided by the total number of customer interruptions. So the average interruption duration a PacifiCorp customer receives by State varies, but is in the range of 80 to 100 minutes or 1.3 to 1.7 hours when compared to the EEI Reliability Survey information in the following section. The actual values are shown below in Figure 8.3.

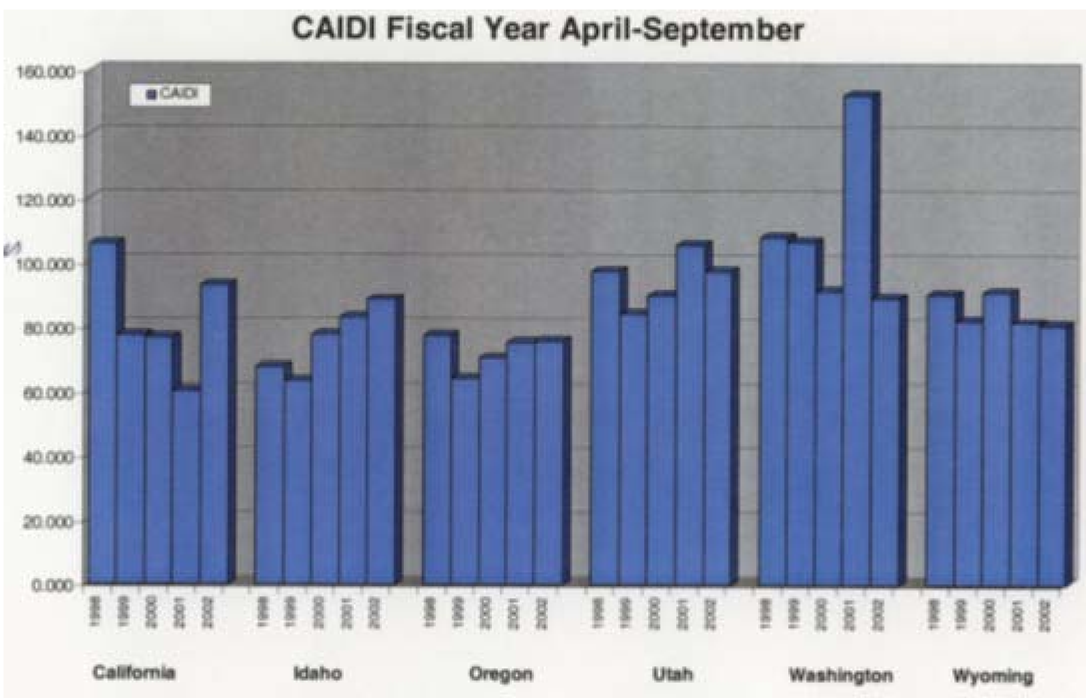


Figure 8.3: CAIDI Values for PacifiCorp by State from 1998 Through 2002

National Perspective on SAIFI, CAIDI, SAIDI, and MAIFI

In order to gain some overall indication of the SAIFI, CAIDI, SAIDI, and MAIFI values, consider the EEI Reliability Survey data for the year 1999. In this survey, 62 companies provided data, an increase of 21 companies over the 1998 report. The national averages for 1999 show an improvement from the data reported in 1998. This is very positive in light of the distribution system failures that were part of the focus of the Department of Energy's Power Outage Study Team (POST) and hearings held in January 2000. The national average for the various indices are listed in Table 8.1 below, with PacifiCorp data ranges also shown for comparison purposes (PacifiCorp data is provided by multiple States). Only data that excluded all major events has been shown.

Entity -	Excludes All Major Storms			
Year	SAIFI	CAIDI	SAIDI	MAIFI
EEI - 1998	1.21	1.80	1.97	5.44
EEI - 1999	1.38	1.42	1.69	11.58
PacifiCorp – Various Years	0.5 – 1.3	1.3 – 1.7	0.83 – 2.3	4.8 – 5.6

Table 8.1 EEI 1999 Reliability Report Summary Compared to PacifiCorp Data Ranges

There are two ways to analyze metric data. One is to compare against industry averages as in Table 8.1 above. There are major differences in weather patterns (i.e., tornadoes in the Midwest, and earthquakes in the West), and customer service territory (urban versus rural) that make such comparisons difficult. However, they do indicate whether the electric utility under study is near average metrics or not. PacifiCorp is either near or better than the national averages for all metrics.

The other more valuable manner of analysis is to compare against previous years in the same electric utility. The trends are what indicate improvement over time. This is what should be important to both the electric utility and its customers – are outages becoming less frequent – are outage durations becoming shorter?

Gathering and reporting of data for metric analysis requires some standardization in the reporting process. Electric utilities normally make the following assumptions and employ the following criteria when calculating SAIDI, SAIFI, and MAIFI. These assumptions are applied when accumulating outage data for standardizing reliability measurements (per EEI):

- Customer's equipment outages will be excluded from the calculation of SAIDI, SAIFI, and MAIFI

- Outages intentionally initiated pursuant to the provisions of an interruptible service tariff or contract and affecting only those customers taking electric service under such tariff or contract
- Interruptions due to nonpayment of a bill
- Interruptions due to tampering with service equipment
- Interruptions due to denied access to service equipment located on the affected customer's private property
- Interruptions due to hazardous conditions located on the affected customer's private property
- Interruptions due to a request by the affected customer
- Interruptions due to a request by a law enforcement agency, fire department, other governmental agency responsible for public welfare, or any agency or authority responsible for bulk power system security
- Interruptions caused by the failure of customer's equipment; the operation of a customer's equipment in a manner inconsistent with law, an approved tariff, rule, regulation, or an agreement between the customer and the electric utility; or the failure of a customer to take a required action that would have avoided the interruption, such as failing to notify the Company of an increase in load when required to do so by a tariff or contract
- Interruptions caused by the actions or omissions of another utility or other supplier of electricity or electrical services as long as the transmission and distribution system facilities of the Company remained operational
- Planned outages by the electric provider will be excluded from the calculation of SAIDI, SAIFI, and MAIFI
- Excludable “major events” will be excluded from the calculation of SAIDI, SAIFI, and MAIFI
- A “Sustained Interruption” is an interruption of electric service that is not automatically or “instantaneously” restored, having duration of greater than five minutes (per IEEE recommendation).
- Momentary outages will be excluded from the calculation of SAIDI and SAIFI
- The beginning of an outage will be recorded at the earlier of an automatic alarm or the first report of no power
- The end of an outage will be recorded at that point when power is restored to customers
- Where only part of a circuit experiences an outage, the number of customers affected will be estimated, unless an actual count is available through some automatic form of data collection. When power is partially restored, the number of customers restored also will be estimated.
- When customers lose power as a result of the process of restoring power (such as from switching operations and fault isolation), the duration of these

additional outages will be included, but the additional number of interruptions will not be included in the calculation.

Detailed Analysis of PacifiCorp Performance Commitments

Now, let's examine more closely the performance commitments that PacifiCorp agreed to attain. This section includes a detailed discussion of each of the various performance commitments.

System Availability - SAIDI

On the five-year anniversary of the completion of the transaction (i.e., the closing of the transaction pursuant to the Amended Merger Agreement), the underlying "System Average Interruption Duration Index" (SAIDI) for PacifiCorp customers in the State of Utah is to be reduced by 10 percent.

The SAIDI index represents the average length of time (in minutes) that a customer experienced electrical outages on the Utility's system during the year. PacifiCorp's definition of calculating the SAIDI value will "exclude extreme events (storms)." This allows measurements of the underlying performance of the asset base.

$$\text{SAIDI} = \frac{\text{Sum of all Customer Interruption Durations}}{\text{Total Number of Customers Served}}$$

The California Public Service Commission has posted the SAIDI metrics from four of the electric service providers within their jurisdiction: Southern California Electric; San Diego Gas & Electric; Pacific Gas & Electric; and Sierra Pacific Power Company. Due to differences in the outage reporting systems (manual versus fully automatic – which will generally report much higher "Customer Interruptions") and the differences in load densities, these levels are not necessarily indicative of those that might be anticipated by the State of Utah from electric service availability by PacifiCorp. Figure 8.5 is reproduced from their website[1]. Note there are abnormal situations that exist from time to time, even when excluding major events such as storms.

[1] http://www.cpuc.ca.gov/static/industry/electric/reliability/saidi_1987to1999.htm

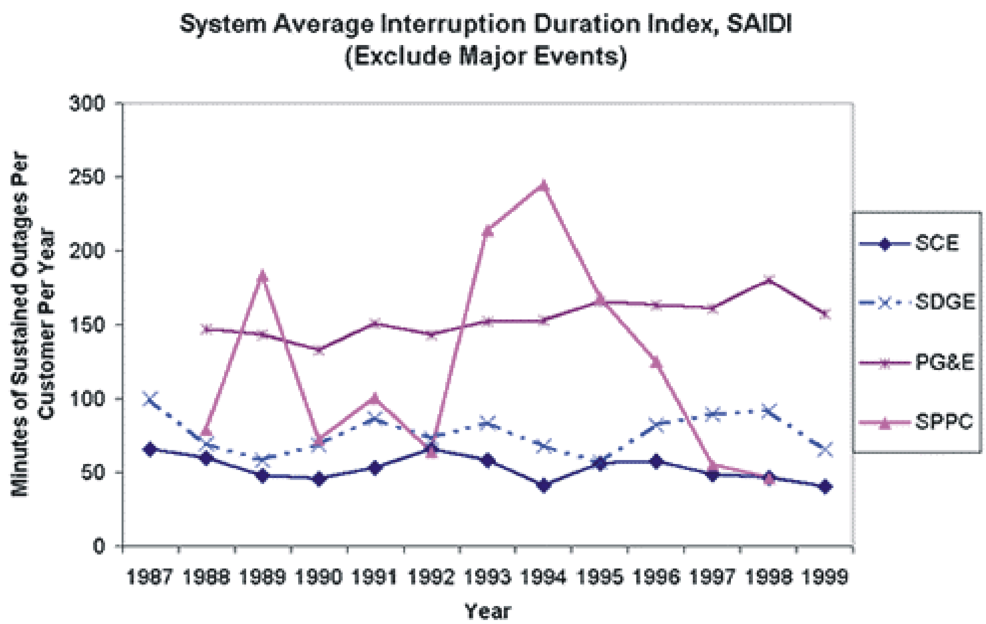
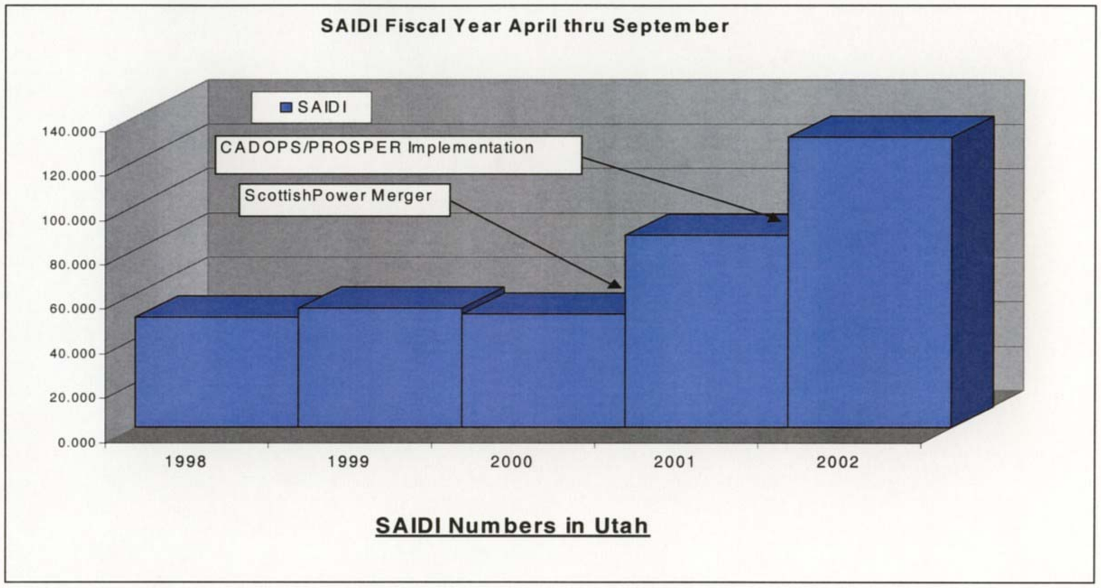


Figure 8.4 Typical System Average Interruption Duration Index Values

Figure 8.5 is a graph of the values at PacifiCorp for only the State of Utah. They fall in the range of 50 to 140, within values that would be expected according to the averages above. Similarly, when converted to minutes, they are near average on a national level. The SAIDI numbers have increased in 2002 due to the automatic reporting of outage data that was recently implemented in 2002. Most electric utilities have yet to install automatic outage reporting software, so the averages are not as useful for comparison purposes.

Again, what is useful in benchmark metric analysis is examining the trends within each utility. In the situation with PacifiCorp, the automatic outage system installation has changed the accuracy of reporting.



- 2001 uplift due to the increased focus on outage reporting
- 2002 uplift increases are due to the introduction of connectivity in CADOPS, uplift minimized by $44.6 M Wasatch Front upgrade project.

Figure 8.5: SAIDI Values from 1998 to 2002 for the State of Utah

System Reliability - SAIFI

On the five-year anniversary of the completion of the transaction, the underlying System Average Interruption Frequency Index (SAIFI) for PacifiCorp customers in the State of Utah is to be reduced by ten percent.

The SAIFI Index is an industry standard measurement of electrical outages. The index represents the average number of times that a customer experienced electrical outages on the Utility's system. SAIFI characterizes the average number of sustained electric service interruptions for each customer during the reporting period. PacifiCorp's definition of calculating the SAIFI value will "exclude extreme events (storms)."

$$\text{SAIFI} = \frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

The California Public Service Commission has posted the SAIFI metrics from three of the electric service providers within their jurisdiction: Edison; Pacific Gas & Electric; and San Diego Gas & Electric. Again, due to differences in outage reporting and urban/rural load densities, these levels are not indicative of those that might be anticipated by the State of Utah from electric service continuity by

PacifiCorp. Correspondingly, the national averages are approximately 1.3 interruptions per year. The Figure 8.6 is reproduced from their website[2].

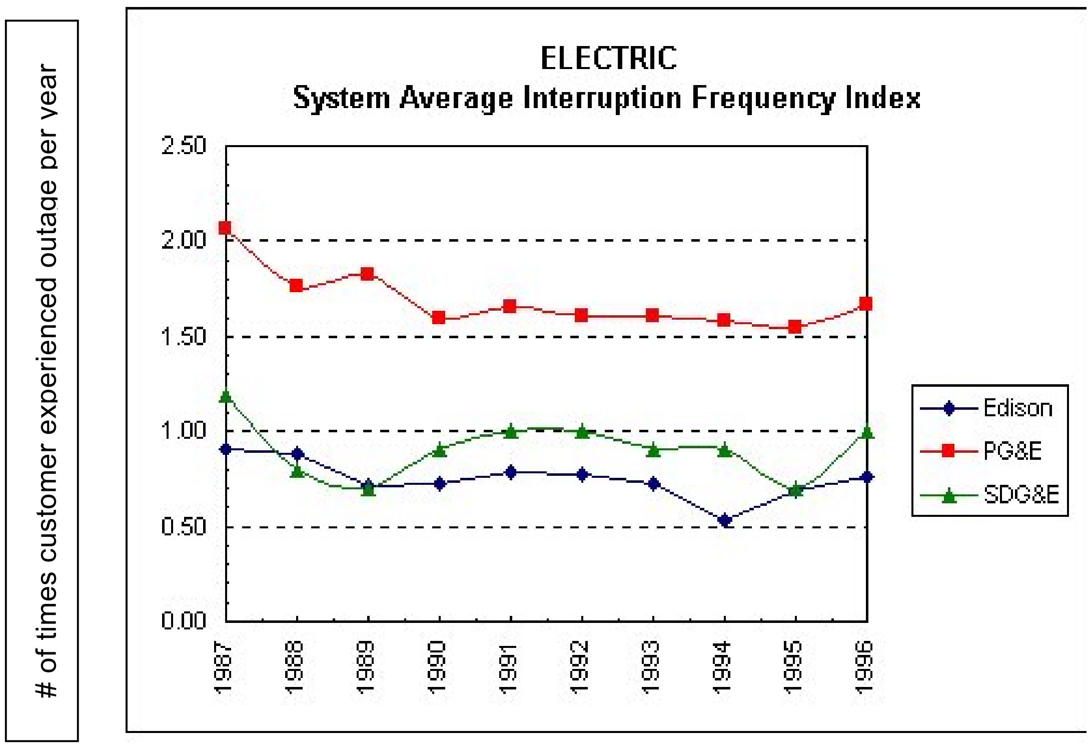


Figure 8.6 Typical System Average Interruption Frequency Index Values

In regard to the SAIFI index, PacifiCorp has been well under the averages experienced by other electric utilities. However, due to the automatic reporting of outages, the values have nearly doubled. The PacifiCorp SAIFI values are shown in Figure 8.7 below.

[2] http://www.cpuc.ca.gov/static/industry/electric/reliability/saifi_1987to1999.htm

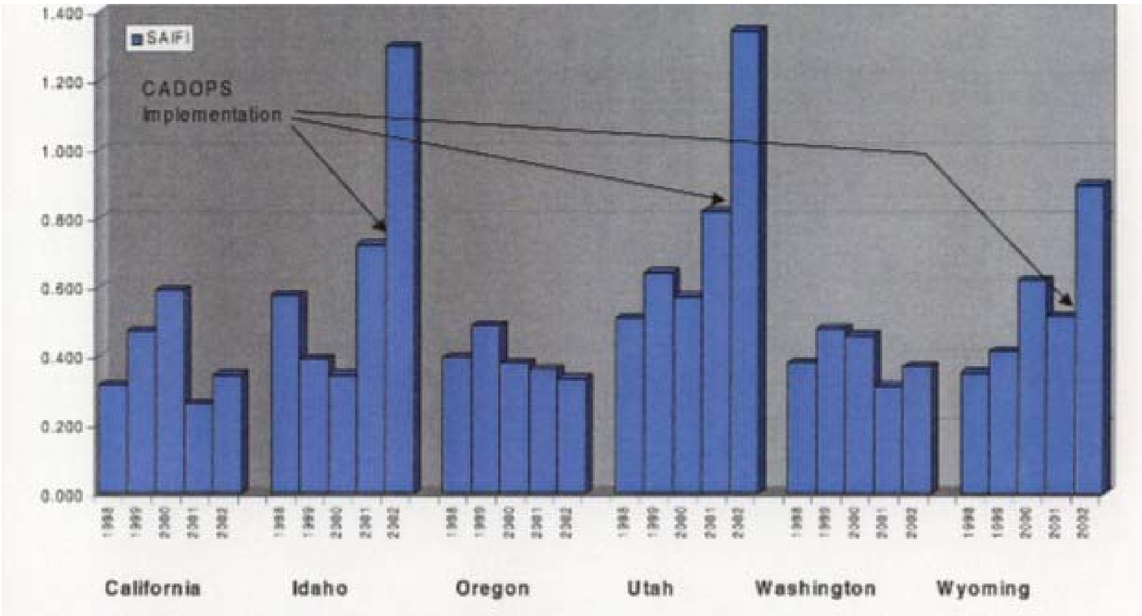


Figure 8.7: SAIFI Data of PacifiCorp from 1998 through 2002 (Fiscal Year April-September)

Momentary Interruptions - MAIFI

On the five-year anniversary of the completion of the transaction, the underlying Momentary Average Interruption Frequency Index (MAIFI) for PacifiCorp customers in the State of Utah is to be reduced by five percent. MAIFI includes all interruptions in a year that are less than five minutes per average customer. The MAIFI Index is not reported by most utilities.

$$\text{MAIFI} = \frac{\text{Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Served}}$$

For an example an east coast urban utility's values of MAIFI, Figure 8.8 has been included. It has data pertaining to the Long Island Power Authority (LIPA) of New York. One can see that LIPA has been striving to reduce their MIAFI values over the years, dropping from a high of 12.5 down to a recent low of 6.9 momentary interruptions per year. LIPA has been implementing a capital intensive distribution automation program across their utility.

Accordingly, PacifiCorp's performance relative to MAIFI has risen slightly, again due to the automatic reporting of outage occurrences. In September 2000, a MAIFI value of 4.8 was reported. And, in March 2001, a value of 5.6 was reported. These values are currently well below LIPA, even with their recent improvement efforts as shown in Figure 8.9 below.

MAIFI Index
(Customer Interruptions per year under 5 minutes)

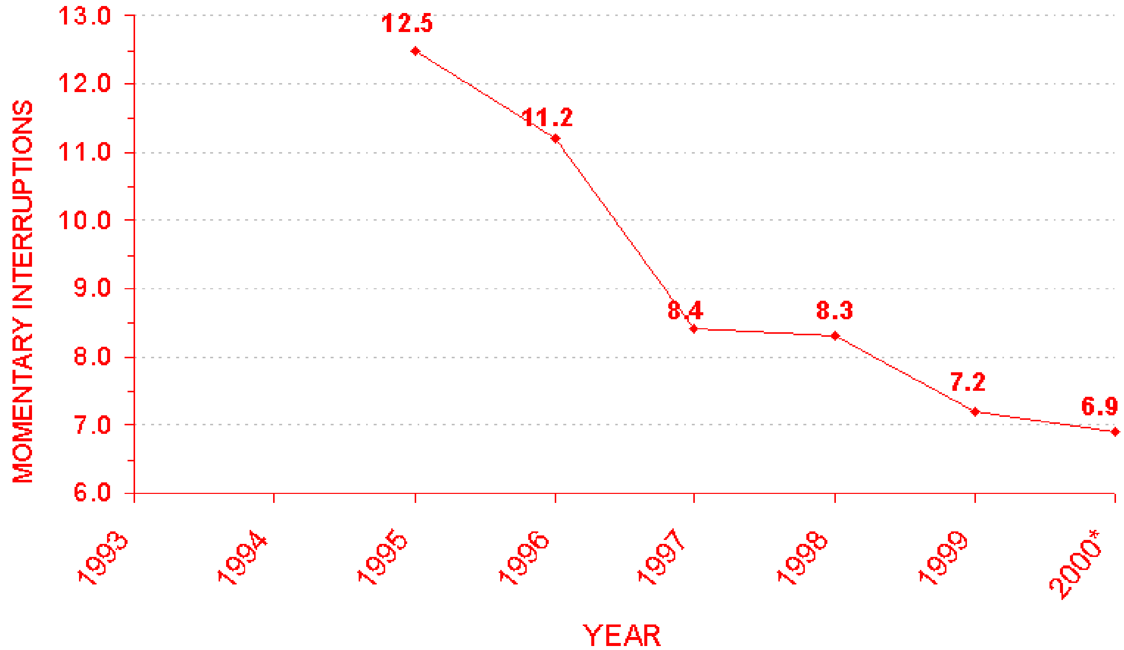


Figure 8.8 LIPA's Momentary Average Interruption Frequency Index Values

Worst Performing Circuits

The five worst performing circuits in the State of Utah will be selected annually on the basis of the Circuit Performance Indicator (new CPI) (the CPI_{99} is a weighted, composite index based on the following four factors: (1) MAIFI, (2) SAIDI, (3) SAIFI, and (4) number of lockouts), as calculated over a three-year average excluding extreme events. Corrective measures will be taken within two years of implementation of the performance targets to reduce the five worst performing circuit's CPI by 20 percent.

With performance standard #4 attendant to the Scottish Power merger of 1999, it was determined that the old CPI needed to be changed. To avoid confusion with the old CPI, the new CPI was called CPI_{99} internally. Table 8.2 shows the components of the three-year metric.

Component	Weighting Factor	Normalizing Factor
SAIDI (minutes)	0.30	0.029
SAIFI	0.30	2.439
MAIFI	0.20	0.70
Sub Lockout	0.20	2.00

Table 8.2 Components comprising Circuit Performance Indicator CPI_{99}

These components are summed together and multiplied by an index factor of 10.645. If a circuit does not exist for the entire three years of the averaging period, its data is prorated (expanded) to the full period. Additional base period calculations are not needed with the new index. Although CPI_{99} is a part of Performance Standard #4 (PS4), it is not used to rank feeder improvement projects for PS1, 2 & 3 because of an inherent averaging problem.

A feeder with less than one year of data has a CPI of “new” and is not ranked. When a circuit is reconfigured such that more than 10 percent of the existing load is moved to another existing circuit, its CHL, SI, SCI, MI, MCI and number of lockouts should be prorated and moved with the load.

CHL: Customer Hours Lost (or Interrupted)

This is the numerator of SAIDI (in minutes) on a circuit, divided by 60. It’s an “unaveraged” metric that directly measures a circuit’s contribution to statewide SAIDI for Performance Standard #1. Hours are used, instead of minutes, so the numbers do not get as large and unwieldy.

SI: Sustained Interruptions

This is the number of sustained interruptions (greater than five minutes).

SCI: Sustained Customer Interruptions

This is the number of sustained interruptions times the number of customers interrupted. It is the numerator of SAIFI on a circuit or zone level. It is an “unaveraged” metric that directly measures a circuit’s contribution to statewide SAIFI for Performance Standard #2.

MI: Momentary Interruptions

This is the number of momentary interruptions (less than or equal to five minutes).

MCI: Momentary Customer Interruptions

This is the number of momentary interruptions times the number of customers interrupted. It is the numerator of MAIFI on a circuit or zone level. It is an "unaveraged" measure that directly measures a circuit's contribution to statewide MAIFI for Performance Standard #3.

CRI: Combined Reliability Index

This index captures, in one number, the effect of CHL, SCI, and MCI used for feeder performance ranking. Data are first screened for *major events*. The index weightings are 40,40, and 20, respectively. This corresponds directly to the relative Performance Standard weightings. Prior to weighting, each of the above components is normalized to a base feeder as with CPI and CPI_{99}. The base feeder value for a component is an annualized three-year average of that component for all of PacifiCorp for the 1997-1999 period, rounded to the nearest whole number. It is calculated as in the example below. If all components are measured to equal accuracy, CRI is the simplest and most direct one-number index for ranking feeders to meet the first three performance standards.

To calculate the base feeder value of CHL, PacifiCorp defines the following identifiers calculated from PROSPER data, with major events and scheduled interruptions screened out:

$CHL_{3\_yr\_PCorp}$ = 3-year sum of CHL for all of PacifiCorp-U.S. Distribution

Feeder_Count = Number of Feeders in PacifiCorp-U.S. Distribution at the end of 1999.

PacifiCorp then calculates the annualized 3-year base feeder quantity for CHL as:

$$CHL_{BF} = \text{ROUND}\ (CHL_{3\_yr\_Pcorp} / \text{Feeder\_Count} / 3)$$

Annualized 3-year base feeder quantities for SCI & MCI are calculated the same way. From this we get

$$CHL_{BF} = 942$$
$$SCI_{BF} = 649$$
$$MCI_{BF} = 4,974$$

An annual CRI for an individual feeder is then comprised of the following data as shown in Table 8.3 below.

Component	Weighting Factor	Normalizing Divisor
CHL	0.40	942
SCI	0.40	649
MCI	0.20	4,974

Table 8.3 Components of Annual CRI for Individual Feeder

These weighted and normalized components are then summed together to get CRI. A feeder with a CRI the same as the "typical" PacifiCorp feeder would have a CRI of 1.00. A feeder with combined reliability twice as bad as the typical feeder would have a CRI of 2.00. If a circuit does not exist for the entire three years of the averaging period, its data is prorated (expanded) to the full period. A feeder with less than one year of data has a CRI of "new" and is not ranked.

To obtain a three-year average annualized CRI, the component metrics (CHL, SCI, & MCI) must be obtained for three years and then divided by three (annualized) before being "plugged in" to the above formula. This will allow a three-year average annualized CRI to be compared directly to an annual CRI without dividing by three. Hence all standard CRI calculations will be directly comparable, whether based on three years of data or one year of data.

CSI: Combined Sustained Index

Inasmuch as momentary data are often considered to be far less accurate than sustained data, it makes sense to use a combined ranking index like CRI, but without the momentary component. CSI is that index, with a 50:50 weighting for CHL and SCI, after normalization. When using PacifiCorp interruption data gathered in an area where momentary data are collected without automatic monitors, this is the most accurate and direct one-number index for ranking feeders with sustained data only. It uses the same base feeder component normalizing divisors as CRI (except for MCI). After a feeder's *momentary* data collection is automated and validated as accurate, CRI should be used instead of CSI.

PacifiCorp will achieve compliance of this metric commitment by improving the service to the five worst performing circuits as required. However, these worst performing circuits primarily exist in rural locations, serving few customers. Hence, the improvements required in the other metrics will not be satisfied with capital and maintenance expenditures required for improving this particular metric. For PS1-3, PacifiCorp reviews feeder improvements based on their total contribution to improve statewide indices.

Supply Restoration

For power outages because of a fault or damage on PacifiCorp's system, PacifiCorp will restore supplies on average to 80 percent of customers within three hours. Again, PacifiCorp's actual performance has been worse than the historical pattern due to past inaccurate measurement and reporting systems. PacifiCorp has made reporting accuracy improvements through installation of the PROSPER automated outage reporting system linked to CADOPS, all in conjunction with the Customer Connectivity Project.

OUTAGE COMPLAINTS RECEIVED BY DPU

The Utah Department of Public Utilities receives complaints from customers of PacifiCorp, as from other public utilities (e.g., Questar Gas and Qwest). The calls attributed to PacifiCorp for the past three years are shown in Table 8.4 below.

COMPLAINTS	1999	2000	2001	SUM
Additional Charges	26	15	12	53
Billing Problems	25	28	16	69
Customer Service	31	21	17	69
Estimated Bill	13	0	1	14
High Bill	28	13	9	50
Initial Service	29	13	10	52
Inquiry (non-complaints)	10	17	41	68
Line Extension	21	11	6	38
Meter Problems/Reads	7	5	12	24
Outage	63	89	84	236
Repair	14	9	10	33
Shut Off or Notices	132	72	52	256
Tree Trim	4	8	6	18
Voltage	4	1	2	7
All Other	16	16	25	57
Total	**423**	**318**	**303**	**1044**

Table 8.4: Complaints Received at Utah DPU from PacifiCorp Customers

Note that except for minor cases, the bulk of customer complaints are dropping over the three years. This is another piece of supporting evidence that while the outage metrics are deteriorating with respect to previous years, those metrics do not reflect a real change in outage frequencies or duration – simply a correct reporting of the facts through the automatic outage reporting system.

DEMAND SIDE MANAGEMENT AT PACIFICORP

PacifiCorp has historically employed both energy conservation and load shifting programs. These were for both residential and commercial customers.

Residential customers were offered two free energy efficient light bulbs. Some special contracts have been written with large customers for load shedding ability.

The Power Forward program in Utah allowed for a green, yellow and red indicator as to the energy usage level encountered. Under yellow, some large customers would take action. Such action would be considered "extraordinary" if a red indicator was posted. PacifiCorp experienced a 50-100 MW demand cut through this voluntary method. This will be instituted again this coming summer. It is not a direct method of controlling load, but it does work.

Nonetheless, PacifiCorp has not yet moved to direct load of their most significant new load, the residential air conditioner. This is currently being explored by the release of a Request for Proposal, "Utah Load Control Pilot," due May 24, 2002. The scope of work is as follows:

Load Control Pilot Overview

1. PacifiCorp (d.b.a. Utah Power) requires a Vendor to implement and maintain a turn-key mass-market Direct Load Control Pilot Program.

2. PacifiCorp requires a Vendor to provide statewide mass-market central electric air conditioning cycling with maximum control and flexibility for load management operations.

3. PacifiCorp requires the ability to manage load demand relief in congestion zones on a priority basis. PacifiCorp shall identify the targeted load relief geographic areas. PacifiCorp requires the ability to pinpoint the area(s) requiring relief at the spot(s) requiring the relief. PacifiCorp requires the ability to cycle the air conditionings by system, region, substation, or circuit. Peak usage in Utah occurs in the summer months from June – September, with July and August being the highest peak usage months. Peak hours are from 8:00 a.m. to 10:00 p.m. daily with the super peak hours occurring between 7:00 p.m. to 10:00 p.m. (excluding weekends and holidays).

4. PacifiCorp envisions a mass market Direct Load Control Program with a two-year development period followed by a maintenance period for the remainder of the Agreement period. Total Direct Load Control Program duration shall be either five years or ten years.

By requiring the ability to control loads by zones, PacifiCorp may alleviate loading on particular substations that are in need of transformer upgrade or require feeder additions. The project's proposed rollout schedule is shown in Figure 8.9 below.

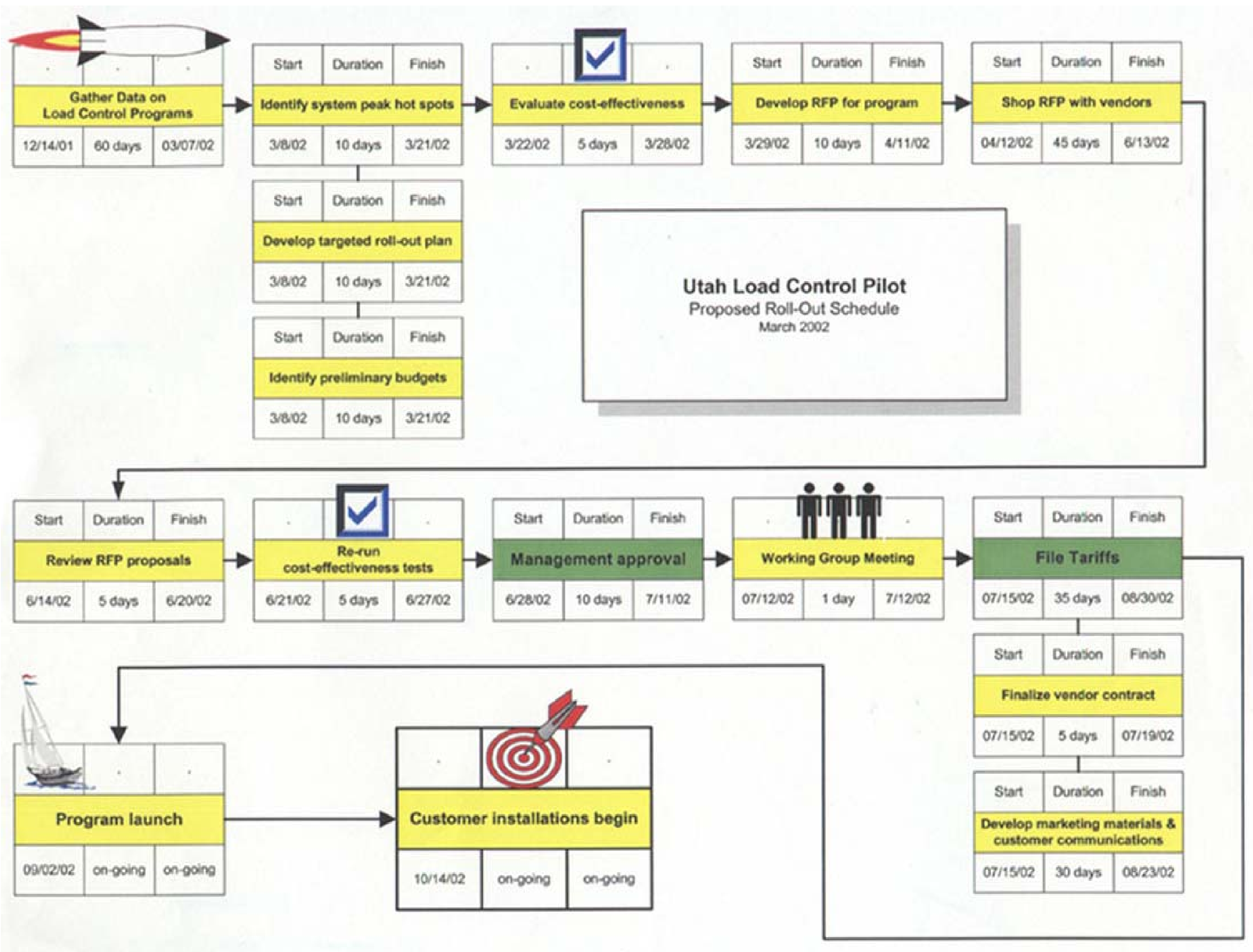


Figure 8.9: Utah Load Control Pilot Roll-Out Schedule

Let's now look at two other electric energy providing organizations and how they have dealt with the issues of designing and installing new facilities (at Salt River Project) and controlling or shifting energy demand and consumption (at Puget Sound Energy).

BENCHMARKING AT SALT RIVER PROJECT

Introductory Comments

The Salt River Project (SRP) of Phoenix, Arizona was interviewed for the purpose of discussing how SRP conducts load forecasting; distribution planning and engineering; distribution automation; and various other broad ranging topics. This information is included in the benchmarking section only because it might be used to compare how PacifiCorp might accomplish similar functions.

An interview was conducted at a high level with the express intention of gathering as much information as possible within a short period of time. In this manner, the State of Utah might better understand how other utilities perform such activities and practices.

SRP had been chosen for this interview because it had been rated highly by J.D. Powers & Associates in the Customer Services Satisfaction Survey last year. It was not chosen because it has similar service territory, customer types, or installed facilities. However, from the aspect that they have been consistently providing reliable and low cost services to their customers, how they operate might be useful to consider.

When it was explained to SRP that the Governor of Utah was concerned about attracting business to Utah, SRP clearly stated that they, too, wanted to attract customers, only into Arizona. So, they should be considered as a competitor in such economic development efforts.

While energy costs climb in neighboring states, SRP customer rates have been reduced three times over the past six years and are on average ten percent less than a decade ago.

Today, generation supply is not only tight in the SRP service area, but throughout Arizona and the West. SRP is planning for reserve levels of about 12 percent for the remainder of this decade. At the same time, the wholesale market has become a less-reliable source for short-term power purchases, due to the decrease in excess supply and the uncertainties throughout the West and Southwest.

For SRP, a vertically integrated public power utility, new resources are needed to continue to keep prices at affordable levels and meet customer demand. SRP's generation planning for the next decade includes the addition of environmentally responsible generation in a stair-step fashion that balances capital costs with customer demand. The addition of two urban generating facilities by 2005 will bring 1,075 megawatts (MW) in new SRP resources, a healthy step toward the additional resources needed to meet their future demand. Other resources may be acquired by increasing SRP ownership percentage in participation plants, and by long-term purchases of generation from plants owned by others.

SRP's plans for new high-voltage transmission lines depend upon generation facilities. The location of generation affects the siting of new transmission lines. SRP owns major transmission lines that move power from their generating stations to SRP's service area and also transports it across the region as required. The SRP transmission system is at capacity, due to energy demand growth in their service area and a directive by the Federal Energy Regulatory Commission (FERC) that allows the use of SRP transmission by other suppliers wishing to sell power to the region.

As SRP's service area continues to experience load growth, maintenance and construction on the SRP distribution system increases. The capital plan for distribution projects inside the service area focuses on infill needs, consistent with the past several growth years.

Nearly 50 distribution substations are planned in the next five years, as well as multiple receiving station transformers, due to load growth resulting from a continued strong local economy. So, the Wasatch Front of Utah is not the only area that is experiencing strong growth.

Distribution system reliability is critical for customers. This past year, SRP's reliability index shows the distribution system's performance at its best ever recorded. This success can be attributed in great part to an aggressive underground cable upgrade program, as well as systematic replacements of wood distribution poles.

In regards to energy conservation, SRP is stepping up efforts to encourage customers to increase the efficiency of their energy use. The SRP energy efficiency campaign promotes a wide range of options to reduce consumption and electric bills.

Customer service is a key aspect of SRP's efforts to make it easy and convenient to do business with them, while providing value through reduced costs and increased efficiency. This year, enrollment in the time-of-use price plans has increased. Benefits of the plan are twofold: customers save on their electric bills, and peak demand is reduced. Another voluntary program for customers is SRP's M-Power© – the largest prepaid electricity program in North America. The program helps participants save as well as reduces consumption on the SRP system.

SRP also provides a large and expanding base of freestanding, self-service pay stations, located at popular shopping locations for customer convenience.

Load Forecasting

SRP performs corporate forecast of: (1) demand (SRP is summer peaking); (2) energy; and, (3) accounts is performed annually. SRP uses forecasts regarding the local area economy to guide the corporate forecasts. Also, the forecast assumes a typical hot summer weather day. There is a separation of trend information by items such as the copper mine customers versus the general commercial customers. This becomes the basis for the six-year financial plan. Input to the econometric forecast include, but are not limited to:

- Population forecast
- Revenue by classification that is aggregated (this is not done by regional area – as SRP has a fairly compact, homogeneous territory)
- WEFA DRI data (note that the local public data sources are described as weak)
- An excellent source of information is "The Aerial Photo Book – The Real Estate Atlas – Phoenix," issued by RUPP Aerial Photography, Inc., ABC Demographic Consultants, Inc., 1726 West Harmont, Phoenix, AZ 85021 (Phone 602.678.4186).

SRP personnel perform all activities associated with load forecasting. The amount of resources is shown in Table 8.5 below. This information may assist PacifiCorp in determining how they might staff, if performing the load-forecasting function on the ABB FORESITE software tool with in-house personnel.

Department	Human Resources	% Utilized for Planning	Full-Time Equivalents
T& D Planning	8	25%	2.0
Corporate	8	70%	5.6

Table 8.5: Internal Load Forecasting Resources at SRP

SRP uses a two-track approach to creating the load forecast. The Corporate group takes a "macro" view, while the T&D Planning group builds the load forecast from the bottom up. They use information from the Key Account Reps who talk directly to the large customers. The value lies in comparing the results of the two methods and discussing the significance of any gaps between them. These groups work well together, understanding each other's needs when working to identify the gaps.

The T&D Planning group uses extreme weather conditions to ensure they are not caught in the five or ten year extreme summer heat conditions. Temperatures of 120 degrees have been experienced several times in the past ten years.

SRP uses a variety of "in-house" developed software application for the load-forecasting model. This has been honed over the years and has proved very adequate to their needs. There is also SAS (off-the-shelf numerical analysis software) for use at the corporate level.

For Transmission and Distribution planning purposes, forecasting is accomplished by dividing the territory into 30 40-acre planning areas. The distribution forecast is a non-coincident forecast done by substation (usually there are four or five substations in the forty-acre planning areas).

A "rule of thumb" has been identified and applied to each of the 30 planning areas. It is called the S-Curve. Figure 8.10 illustrates the S-Curve. It begins low (load level in a planning area) and then begins to rise. As others find this area to be a "growth" area for development, the growth rate increases sharply.

SRP has found that areas experiencing this part of the growth curve are much less affected by economic recessions or down turns of the economy. Later, the curve levels off as the area becomes saturated. The low end of the curve is when load density is about two MW/mile^2. As growth continues over 15-20 years, the area becomes saturated at about 12 MW/mile^2.

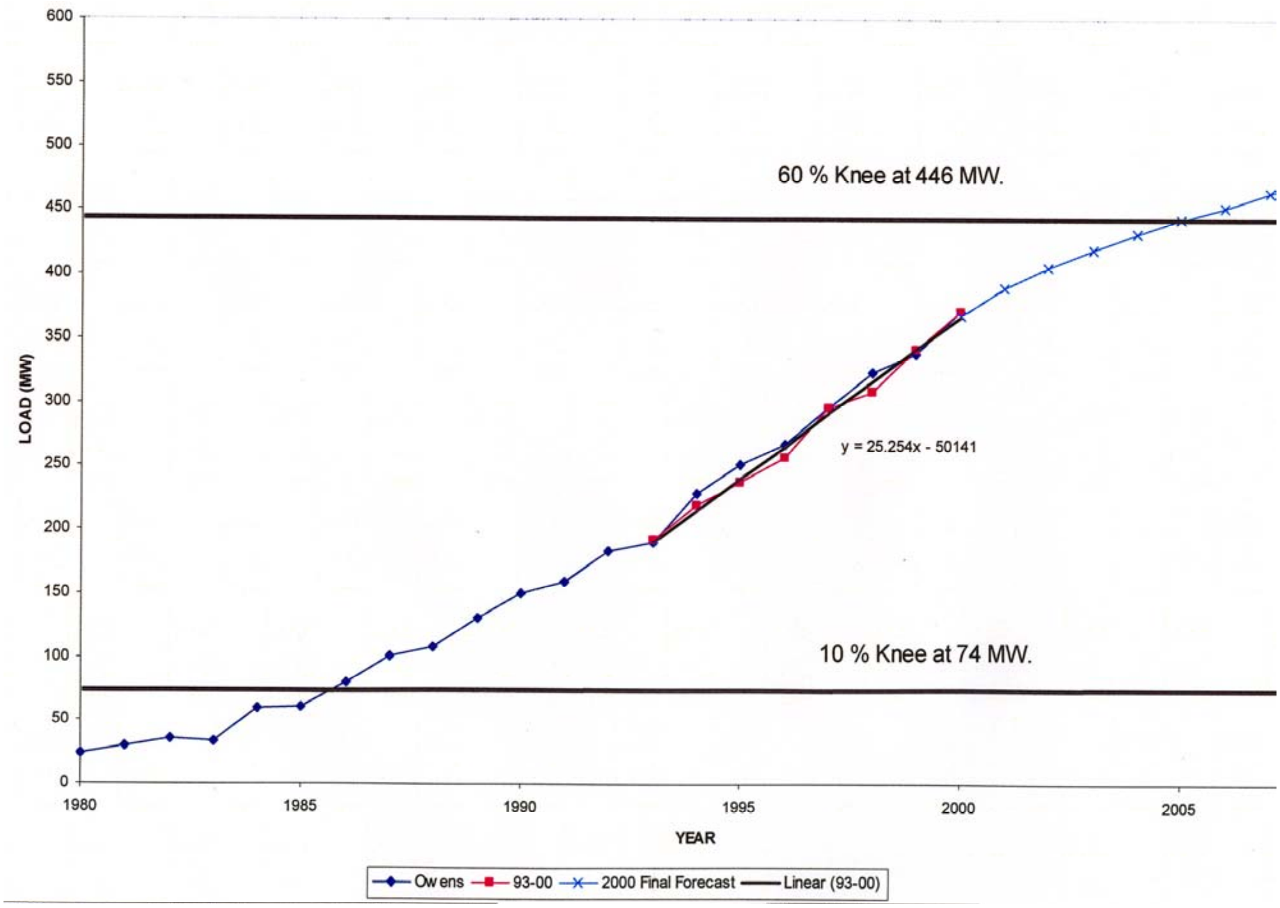


Figure 8.10: Load Growth Forms an S-Curve (Courtesy of Salt River Project)

Demand Side Management (DSM)

SRP has implemented Time-of-Use Metering as a Demand Side Management (DSM) tool. They also have Interruptible rates for large customers. Since it has not amounted to a significant MW load, further initiatives of this nature would be met with some degree of skepticism by SRP management.

This is in direct opposition to the work being accomplished in utilities like Puget Sound Energy (PSE). PSE won the Utility of the Year award for 2001 based upon their effort in DSM. They have achieved measurable results – deferring demand levels in the range of 45 MW during their 2001 peak period.

Also, PacifiCorp's 20/20 Customer Challenge and 10/10 Customer Challenge programs have met with measurable success. This program allowed customers reducing their energy consumption by 10 to 19 percent to receive a ten percent credit, while those saving 20 percent or more would receive a 20 percent credit on their monthly billing statement. The program participation rate experienced in Utah was 22 to 26 percent.

Planning Criteria

The SRP territory is mainly urban in nature and has numerous distribution and transmission loop feeds. When planning for radial systems, there's a large difference in the amount of load that can be reliably served when compared to loop feed systems. By comparison, the PacifiCorp facilities along the Wasatch Front consist of a mixture of looped and radial feeders.

There are five or six mobile substations for use by SRP to maintain, not restore, service. SRP does not consider a 14-hour interruption to service as being acceptable to their customer base. Therefore they do not typically use the mobile substations in their planning criteria for emergencies. Conversely, they perform much switching in order to pick up load that has lost its normal source of feed.

This is different than the service interruption duration that PacifiCorp employs. See "Section 7 - Distribution Engineering" of this report for further details on use of Mobile Substations at PacifiCorp.

Instead of picking up cold load, mobile substations are installed to reduce loading on existing equipment that is experiencing high load levels unexpectedly. This could be caused by transferring load from adjacent facilities that are out of service. Mobile Substations are also used for planned outages of existing facilities and for backup for large dedicated substation customers, if there are any available.

Arizona Public Service (APS) serves load adjacent to SRP. They have some transmission ties between each other that can serve to maintain supply under both normal and emergency conditions. Their relationship was best described as 50 percent competition and 50 percent cooperation.

Additionally, there is a penalty charged to customers who drop below an 85 percent power factor.

Transmission Lines

As PacifiCorp, SRP uses the typical N-1 approach to planning for expansion purposes, meaning the transmission system will be able to have one element out of service at a time without any customers being out of service.

They begin by using a Western System Coordinating Council base case and add their 69KV system, with loads from the forecasting groups. They study the model for overloading of lines, possible under-voltage conditions, and reactive margins.

They conduct the study by assuming a ten MW load is randomly added somewhere in the system (representing an unexpected new commercial or industrial load). They refer to this model as “Plus 10.” All N-1 conditions are run for analysis. They also do a “Plus-20” analysis in later years.

They use the General Electric Positive Sequence Load Flow program and the Aspen One-Liner for short circuit analysis.

The Independent Power Producers make it more difficult to design the transmission system by adding generation in places that may not have adequate transmission capacity. Additionally, there may be times when SRP imports as much as three-fourths of their load requirements. This aids operational flexibility.

Through dynamic conductor monitoring, SRP has been able to increase the load levels on their transmission lines. These are specific to each line and are performed as a means of increasing load-carrying capabilities, while deferring transmission investments.

New transmission facilities require about three years from initial start date to go-live date. Therefore, some lines might be placed in the plan for installation and it may become delayed due to a lower growth rate experienced over the period.

Substations

Substation transformers are loaded to 105 percent to 115 percent of nameplate ratings for planning purposes. The system average utilization for substation transformers is 70 percent of the emergency rating or 88 percent of the nameplate rating. They had loaded to higher levels in the past and had significant problems in maintaining reliable service to their customers. Also, under emergency loading conditions, SRP operates the equipment at 125 percent to 135 percent of nameplate rating.

PacifiCorp is striving to obtain an average substation utilization level of 80 percent of the nameplate rating. This is in line with SRP’s findings, however there have been no studies done to date that indicate the optimum level for PacifiCorp’s territory. Figure 8.11 illustrates the anticipated substation utilization levels in the event all proposed capacity addition projects are completed on time.

If one were to average each of the four blocks composing the year 2006 anticipated utilization levels, the average substation utilization level would be about 76 percent as the following formula illustrates:

$$[40\% \times 0.32] + [85.5\% \times 0.20] + [95.5\% \times 0.44] + [115\% \times 0.4] = \underline{76.52\%}$$

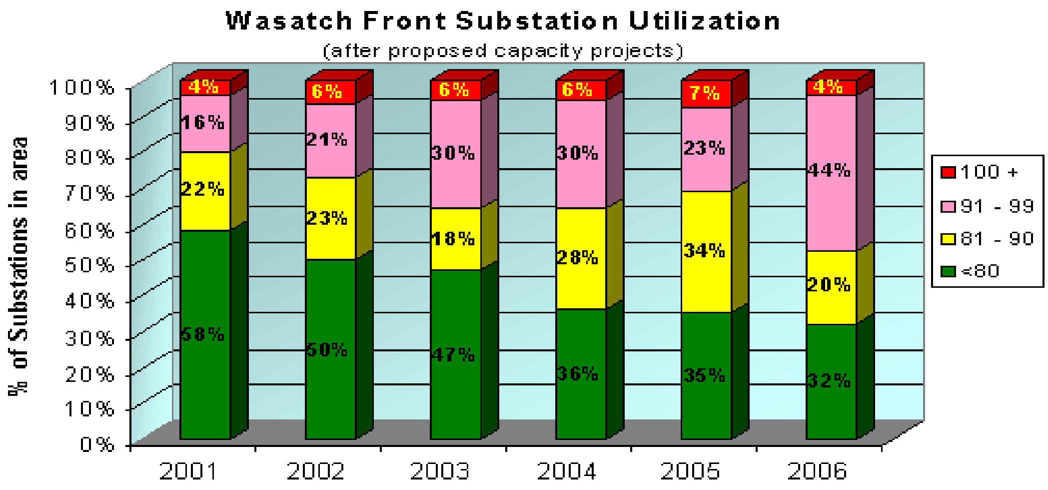


Figure 8.11 Anticipated Wasatch Front Substation Utilization levels

Distribution Automation (DA)

Distribution Automation began approximately ten years ago as a means of providing more reliable and continuous service to "sensitive" customers. Over the years the bugs have been slowly eliminated and it is now a fairly stable and reliable tool.

They have automated commercial areas that are served by underground cables. They have sought to improve the operation of the existing system in this manner, in addition to underground cable upgrades.

There are some areas that have been fully automated, however, they are currently on manual control until they have proven to be fully reliable.

The general conclusion made by SRP is that Distribution Automation is not feasible everywhere – it does not pay on a wholesale basis.

PacifiCorp has also been experimenting in the use of Distributed Automation. It is unclear exactly how extensively it has progressed at PacifiCorp. However, it does provide for deferring asset investments when load can be automatically shifted to adjacent substations during outage contingencies.

Distributed Generation

SRP has performed studies over the past eight to ten years to determine if installing distributed generation on their system at strategic locations would allow for deferring new plant investment. A five MW transportable combustion turbine generator was purchased and operated to reduce high cost purchased power a year ago. Now it cannot be operated economically due to the lower cost of generation. Therefore, SRP is seeking to sell the generator.

Their studies have shown that in order to defer transmission lines, the generator size would need to be 50MW, not five MW. Additionally, the cost to move and obtain a fuel source for the “transportable” Combustion Turbine generator was cost prohibitive.

SRP believes that Commercial and Industrial customers can use co-generation to their economic benefit, however they have not pursued controlling such customer owned generation through a central point of contact.

This is one area that PacifiCorp might consider investigating. Distributed Generation (DG) placed in certain areas of their service territory could potentially defer construction of new transmission and/or distribution facilities. PacifiCorp could provide financial incentives in various forms to the larger customers to install DG at their premise. PacifiCorp would then dispatch the DG as needed or on a purely economic basis (as determined by the System Control Automatic Generation Control software).

Metrics Tracked

SRP tracks the usual metrics associated with delivery of reliable service to its customers. They are SAIFI, CAIDI, SAIDI, and MAIFI. This is similar to PacifiCorp’s metric tracking activity, however no metric data was secured from SRP.

Security

SRP had increased security measures since September 11. There have been additional gates and security guards added. They are moving to a more automated operation of remote equipment.

Studies have been performed to prevent cascading outages on transmission lines. And, they have created and maintain a black-start plan in conjunction with Arizona Public Service.

In addition to the normal over/under frequency and over/under voltage protection relays that shed load, SRP has initiated an “Arm-to-Trip” plan that is tied to multiple contingency outages.

Security issues were not addressed in discussions with PacifiCorp.

Incentives

There is an incentive plan that awards compensation based upon goals established at the corporate, department and personal level.

SRP also offers spot awards to individuals who have been nominated by others as contributing to the success of the organization. These awards are for a few hundred dollars.

PacifiCorp provided awards to representatives from departments who worked on the extensive list of projects during the summer of 2001. They were invited to an award dinner in Portland. Not all those involved with the construction projects were invited, due to the cost associated with bringing all those into Portland. Therefore, only about 70 people were invited as representatives of those departments involved.

Training

Goals regarding training are established and tracked individually by employee. All necessary training is provided. This is similar at PacifiCorp.

BENCHMARKING AT PUGET SOUND ENERGY

Introductory Comments

As a second electric utility to interview, Puget Sound Energy (PSE) was chosen. They have been awarded the 2001 Utility of the Year award for their work in Demand Side Management. The interview with PSE lasted approximately four hours. They provided extensive information on their programs and how they showed measurable success in both deferring and conserving electrical demand.

Printed in the Seattle Times of Sunday, July 2, 2000, was the headline, “Puget Sound Region on Brink of Blackouts.” Reportedly, Puget Sound Energy came dangerously close to running out of power. At a time of year when the Pacific Northwest usually exports surplus power to California, a few days of hot weather and a short circuit 200 miles away left regional utilities scouring the grid for electrons to keep air conditioners humming.

The region survived with no blackouts. But the unexpected shortage sounded a wake-up call to the Northwest that indicated the era of boundless electricity was over - at least for the near future. The PSE service territory is 65 percent suburban, 15 percent urban, and 20 percent rural in nature.

“We have a supply problem, pure and simple,” said Rudi Bertschi, board chairman of Energy Northwest, the public agency that runs the nuclear Columbia

Generating Station near Richland. “Energy demand is growing, and we have not added generation to keep up.”

That was the summer of 2000. Now, *Electric Light & Power* magazine has recently chose Puget Sound Energy (PSE) as its “Utility of the Year” for 2001. The honors stem from the Washington state utility’s launch of an innovative time-of-use energy-pricing program called Personal Energy Management^{TM} Program. The Program rewards consumers for using electricity more efficiently and inexpensively.

PSE has “changed its way of thinking” in order to develop its energy conservation program and “is now the leader for the rest of the country in terms of demand side management.

This Program is the nation’s largest undertaking to price electricity based on the time of day it is used while also showing customers the comparative, fluctuating cost of providing their energy. About 320,000 homes and businesses currently pay PSE’s time-of-use rate for electricity.

PSE has installed Automatic Meter Reading at 1,200,000 of their 1,500,000 customer meters. Note that the pricing structure passes on the *real* cost to the ratepayers. These are both the fixed and variable costs:

Fixed Costs:

- Power lines
- Meters
- Labor
- Supply Contracts

Variable Costs:

- Cost decreases/increases pass through monthly to ratepayers

Personal Energy Management

Puget Sound Energy (Electric Co.) merged with Washington natural Gas (Natural Gas Co.) in 1997. During the rate case presentation PSE committed to holding rates flat for five years and committed to expend $25 million dollars over a three-year period (1999-2001) on Energy Efficiency Efforts and Services. PSE efforts were in the $6-7 million dollar range for 1999 and 2000, and over $16 million in 2001, exceeding their target.

Following the merger, PSE turned inward and focused on becoming one company and finding internal efficiencies. PSE saw value in DSM efforts from a corporate perspective. Their first investment in DSM focused on Commercial and Industrial, not Residential. The Personal Energy Management (PEM) initiative is targeting the Residential customer.

PSE does not utilize a Geographic Information System (GIS), but did invest in a Customer Information System (CIS), Call Center, and Automatic Meter Reading (AMR) technology to get real time pricing data for supporting the PEM effort. The PEM focus is on Dynamic (real-time) Pricing.

The PEM initiative focused on education and piloted 400k customers. PSE modeled the variable rate periods and showed that even with no change in usage, the customer would incur a two percent impact at most.

PEM provided customers with significant usage information through the Internet.

PSE received overwhelmingly positive response from customers. During the pilot of the program, 80 percent took action without being offered incentives to do so. 91 percent took action with variable pricing incentives. 89 percent shifted usage time frames. In a nine-month period 42 MWh was saved.

The next phase is to roll out PEM functionality to all customers. PSE wanted to have an “Opt-out” approach, where customers would be in program unless they directed PSE to not include them. Since the program was well received and has a waiting list of customers who have asked to be on the program it was expanded, so the opt out approach was preferred. However, regulators have decided on the approach that requires customers to specifically sign up for the program. Regulators (concerned over Qwest opt-out approach) directed PSE to use an opt-in approach (customers must request to be included in program), this will require more advertising and outreach on PSE’s part.

PSE has seen revenue gain from PEM in measurable terms.

Note that some do not feel PEM is “true conservation tool” in that more permanent physical conservation measures are the only true sustainable conservation – behavioral modifications are at times not sustainable. Some theorize that time-of-use could result in running coal plants for base load – which would be even harder on the environment.

PSE will be looking for ways to market the benefits of PEM and incorporate traditional conversation approaches.

Since gas is bought and managed on a daily increment – PSE is not anticipating managing gas the same as electricity (PEM).

The current AMR technology installed by PSE is being used to its capacity and has some limitations and gaps in data collection. To do more functionality at the customer end would require improved technology. By installing a lower capability AMR collection device, the initial costs were lower and the payback faster.

PSE's "Energy Efficiency Services Program"

The following information has been provided from Puget Sound Energy and due to its concise explanation of their DSM Programs they offer to their residential customers, it has been included in its entirety. This information goes far in detailing initiatives that might be undertaken by any utility endeavoring to reduce peak demand levels. The publication is titled: "Energy Efficiency Services Program Results" January – December 2001, dated February 15, 2002. It describes the Demand Side Management activities that earned them the Utility of the Year Award for 2001.

Executive Summary

The year 2001 was a year of unprecedented public visibility and customer energy management opportunity, driven by the regional energy crisis. As customer inquiries for energy assistance more than doubled early in the year, PSE was fortunately positioned to deliver a broad range of tools and services to help customers meet their needs. New *time-of-day information technologies* and the Personal Energy Management (PEM) campaign were launched during this same period, creating even greater public awareness and participation in broad-based solutions. New online tools included the opportunity for most customers to see their actual hourly energy usage on a daily basis for each day of the week over the preceding 30 days. A substantial investment was also made to offer customers a Conservation Incentive Credit (CIC) for monthly energy savings greater than ten percent of their usage in the previous year. All of these circumstances contributed to exceptionally high levels of customer participation in mainstream efficiency programs throughout the year.

In the fourth quarter, PSE also completed development of a new Greenpower program, and began taking customer sign-ups in January. Customers may now support the delivery of wind power or other environment-friendly generation into the northwest power grid through a payment on their monthly bills. An average of 20 customers per day have registered for Greenpower since its launch, and additional promotional activities are anticipated.

As 2001 represents the final full year of a three-year program commitment, PSE reported that all program targets, established in consensus with the Technical Advisory Group and set in tariffs approved by the commission in early 1999, were exceeded as of December 31, 2001. Energy savings results were 79 percent above early projections in electric programs, and more than double the projections for gas programs. Spending levels also exceeded original estimates, although a strong commitment to cost-effective delivery resulted in a lesser excess than the savings, about 16 percent, over the three-year period. All commitments, results and spending levels are summarized in Tables 8.6 and 8.7, and Figures 8.13 through 8.15, at the end of this section.

As new discussions around future programs proceed, the observations and results described in this report can help guide the development of new and modified services to be those most appropriate for assisting customers with their overall energy management needs. PSE is looking forward to continue leveraging customer awareness of energy market issues to build interest in new and improved web-based tools such as the Personal Energy Profile, which was launched at mid-year. Additional tools as described in the report, for helping both residential and commercial customers with as many facets as possible of their energy management interests and needs, were also launched in 2001.

Program Activities

The following DSM program activities are provided as examples of how PSE was able to move their customers to either shift demand or conserve energy. They may or may not prove useful to PacifiCorp as it considers DSM program activities beyond its current 20/20 and 10/10 Customer Challenge programs.

Residential Energy Efficiency Services, Schedules 200/206

PSE's Residential Energy Efficiency Services (REES) help customers to efficiently use energy and reduce their energy costs by providing recommendations and detailed information through various REES tools. Key elements of REES include a telephone hotline (1-800-562-1482), a home energy audit known as Personal Energy Profile (PEP), and a family of brochures that answer a comprehensive range of questions about energy use in the home.

Customers request the Personal Energy Profile (PEP) and energy efficiency brochures over the phone, by mail, and PSE website facilitated e-mail. An online version of PEP, as well as other energy efficiency information and calls to action are also available on the Company's website: www.pse.com.

In addition to useful information and calls-to-action provided on the website and in printed materials, personal energy advisors staff the Hotline to answer customer questions and offer guidance over the phone. Ongoing training continues to expand the energy advisors' ability to answer a broad range of energy use questions and direct the customer to needed resources. To promote the understanding of the rate offerings, PSE offered a colorful refrigerator magnetic as shown in Figure 8.12 below.

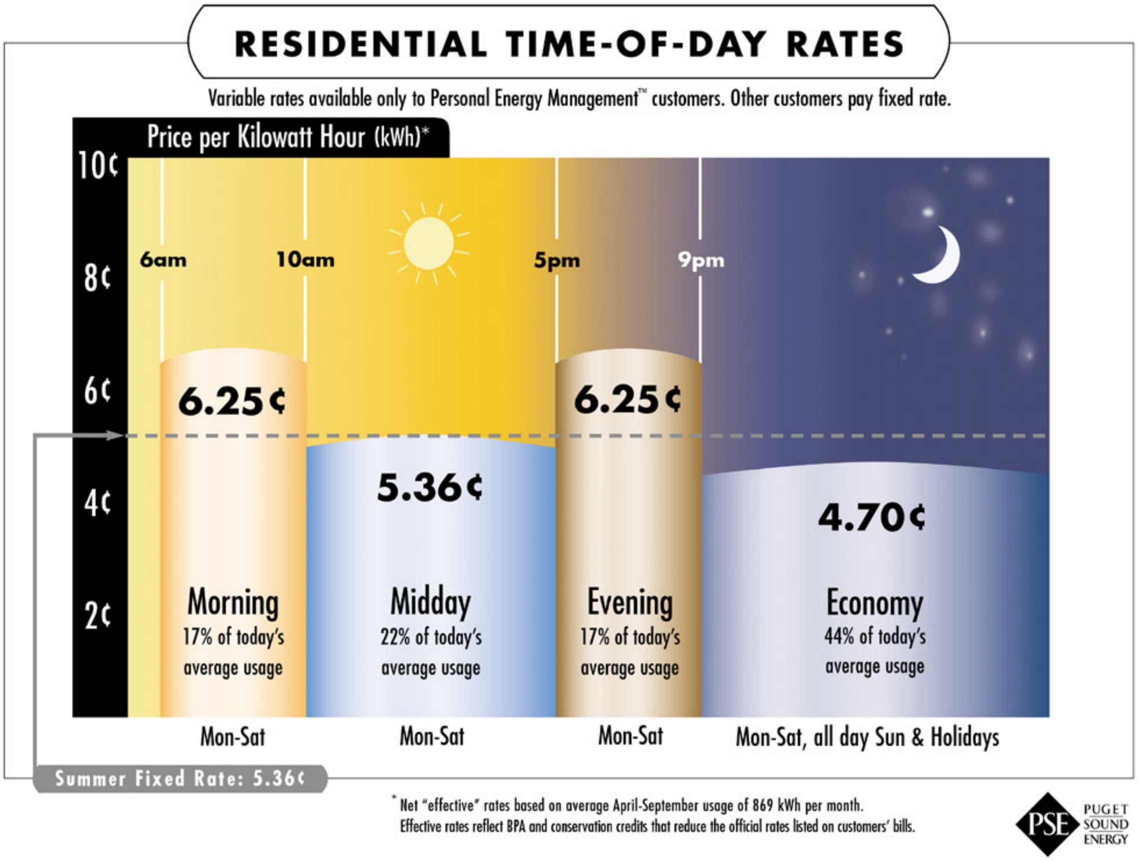


Figure 8.12: Refrigerator Magnet Illustrating Time-of-Use Rate Impact

Notable highlights for Residential Energy Efficiency Services in 2001 include:

- More than 4,872,000 kWh of electricity and 358,000 therms of natural gas saved.
- 146,800 residential customer requests for energy efficiency information and recommendations by phone, mail and e-mail.
- More than 45,900 residential customer calls answered by the Energy Efficiency Hotline.
- Over 27,800 customers requested the paper version of Personal Energy Profile.
- Approximately 72,900 customers requested other printed materials, seeking specific energy saving information and tips. Customers requested these materials through PSE's website, by returning bill inserts, or by calling the Hotline. Over 124,000 PDF files of conservation brochures were downloaded from the PSE website.
- 2,058 customers accessed PEP online between May and year-end. Through the Internet, customers may quickly obtain energy saving recommendations

and an action plan, based on their answers to a series of questions. Since October, when customers' access to PEP required logging into PSE's newly developed Personal Energy Management Center, the average time customers spend on PEP has steadily increased. Looking into 2002, online volume is expected to increase with greater visibility and customer awareness. The paper version of the PEP home audit survey will also continue to be available.

- More than 3.5 million bill inserts were mailed to customers to inform them of available residential energy efficiency services in 2001. In addition, energy efficiency tips and calls to action were included in the monthly Energy Wise Newsletter, delivered with customers' bills.
- Numerous presentations were made to consumer groups including senior citizens, neighborhood associations and others regarding efficient use of electricity and natural gas.

PSE has recently developed the Personal Energy Management Center, which provides a central location for customers to access PSE's online, energy management tools. Once registered, customers have access to energy profile tools, calculators, a reference library, a product store and a contractor referral service. The PEM center provides tools customers can use to understand their energy use, create an action plan and have access to resources to put their energy plan into action. In addition, customers can subscribe to PSE's e-newsletter, which will be an on-going way to keep customers engaged in managing their energy.

In August 2001, customers served by PSE, Seattle Public Utilities and their water purveyors received an offer for a free Conservation Kit. The kit included a low-flow faucet aerator, a flow bag to measure water flow of faucets and showers, a discount coupon for an energy star appliance purchase, and rebates for efficient gas water heaters and low-flush toilets. In addition to the conservation kit, PSE offered customers the Personal Energy Profile. By the end of 2001, approximately 4,000 customers requested kits. Of those, 1,200 requested a PEP survey. More than 800 of these customers subscribed to PSE's Personal Energy Management E-newsletter. The costs for this joint effort were shared equally with Seattle Public Utilities, and PSE is grateful for the opportunity to participate. In addition to shared costs, SPU also provides a link from their website at www.savingwater.org to PSE's Personal Energy Profile at www.pse.com.

Residential Low Income Programs, Schedules 201/203 and 209/209

The Washington State Office of Community Development (OCD), provides administrative oversight including funding distribution and data reporting for implementation of the home weatherization programs conducted under electric Schedule 201, gas Schedule 203 and electric and gas schedules 209. Program services are delivered to customers through 11 county and municipal low-income assistance agencies operating in the PSE service area.

Notable program highlights in 2001 include:

- 537 low-income homes weatherized, with estimated energy savings of more than 703,800 kWh of electricity and 34,510 Therms of natural gas per year
- 905,000 bill inserts were targeted to low-income single-family gas and electric customers, to increase awareness of available home weatherization services; customers who called the Hotline regarding low income were referred to low-income assistance agencies for weatherization and other services
- Customers referred to low-income weatherization agencies were also offered the brochure, *Weatherization Assistance for Low Income Customers*; in addition, they were eligible for PSE's other residential energy efficiency services

Efficient Gas Water Heater Program, Schedule 201

The gas water heater rebate program had 2,625 customers participated in, saving 86,625 therms of natural gas during the year. We continue to promote builder participation and increased installation of efficient tanks in the new construction market.

Contractors may now send rebate requests electronically, and a process for verification of qualifying tanks was implemented in 2001. As contractors become more familiar with the new process, volume is expected to increase.

In Concert with the Environment, Schedules 202/207

In Concert with the Environment (In Concert) is a secondary school program that teaches students about natural resources and their use. Students learn the definition of renewable and non-renewable natural resources. They are shown examples of each and how we use natural resources in our daily lives. A key objective is to teach students about the choices they make and the impact their choices have on our environment and natural resources. Students participate in a variety of activities and demonstrations focusing on energy, water, solid waste, and air quality.

A key component to the curriculum is a computer program that leads the students through a home energy audit and concludes with a report detailing their energy use and ways to save energy.

During the 2000 – 2001 school year, In Concert served over 11,000 students in 60 schools. The estimated annual household savings are more than 565,000 kWh of electricity and 61,100 Therms of natural gas.

Contributing to the success of In Concert are the partnerships with neighboring municipalities and utilities. In Concert has raised over $120,000 in cooperative funding through 23 partners. Partners include the Seattle Public Utilities and

Snohomish County PUD. In addition, In Concert has a working relationship with the Electric League of the Northwest through its 501-c3 non-profit entity – The Education Foundation of the Electric League – to facilitate additional grant funding from third parties.

Residential Duct Systems, Schedules 203/204

Phase I of the Duct Sealing Pilot was completed in the fall of 1998, and project results were analyzed and formally reported in early February of 1999. Phase II is also now complete, marked by a final report covering field diagnostic testing results on 52 heat pump-equipped homes. The findings of Phase I (covering primarily gas furnaces) and Phase II (heat pumps) have been the basis for planning Phase III of the pilot.

Phase III was designed to test the knowledge gained about duct and heat pump systems in phases I and II, under a more market-oriented environment that would ultimately involve a heating and air conditioning contractor performing heating duct leakage diagnostics and advanced diagnostics of the electric heat pump.

Incentives of $100 or $150 were offered to homeowners in Phase III who agreed to participate. The lower payment was offered for a complete diagnostic test and inspection of the heat pump. The higher payment was for both heat pump diagnostics and heating duct leakage measurement. The customer was required to pay the balance of the costs. The full invoice cost of the diagnostic service was $250 or $350, plus sales tax.

A total of six field diagnostic (research) visits were conducted by year-end. Four participants purchased the comprehensive heat pump and duct diagnostics and two purchased the heat pump diagnostics only. All of the heat pump installations had the indoor and outdoor coils (heat exchangers) cleaned.

Coil cleaning and minor systems adjustments are projected to save about five percent in annual heating and air conditioning costs. Based on average heating consumption (for these homes) of 12,000 kWh per year, the savings are estimated to be approximately $50 per year. In five cases, the heat pumps required additional repairs or service. Participating homeowners had responsibility for getting contractor bids and paying for the cost of the recommended repairs. Projected annual energy savings per system for repairs and major service is estimated to range from 15 percent to 30 percent. Additional bill history analysis and customer follow-up work is due to be completed by March 31, 2002.

In November 2001, two trained heating contractors with duct diagnostic and sealing equipment were recruited to participate in a market-based field test of heat pump and duct diagnostics. A pilot utility incentive of $75 is offered to customers for heat pump service performed in accordance with the advanced diagnostic testing methods developed during Phases II and III. An additional $75 incentive is offered for a completed heating duct diagnostic test performed by the same certified heating contractor. A report of the filed test results is expected by March 31, 2002.

Compact Fluorescent Lighting, Schedule 205

Schedule 205 is administered in coordination with Northwest Energy Efficiency Alliance lighting initiatives. PSE offers a rebate of $25 or 40 percent of cost (whichever is less) to builders, developers or owners of new construction and major rehab multi-family facilities for each qualified energy efficient compact fluorescent lighting fixture installed.

Schedule 205 gained momentum in 2001 through increased promotion to targeted industry contact lists and electronic distribution of program information and rebate application forms. Rebates resulted in 1,351,075 annual kWh saved and 2,490 fixtures installed during 2001. More than 800 builders, developers, and architects were provided with program information and participation materials.

Finding additional opportunities for promoting efficient lighting, PSE influenced change in fixture procurement practices at Microsoft Corporation with a 3,000 torchiere turn-in program planned at Microsoft facilities for March 2002. Also, a cooperative effort with Seattle City Light, resulted in development and completion of an efficient lighting fixture website, www.elflist.com.

High Efficiency Clothes Washers, Schedule 206

Schedule 206 offers a $50 rebate for the purchase of efficient washing machines in multi-family laundry facilities and coin-operated Laundromats with electric water heat. During 2001, PSE increased awareness of the program by direct mail and personally contacting multifamily building owners, property managers, and laundry route companies. This resulted in 71 washer rebates for a total of 56,800 kWh savings. There are few potential customers for this electric program, since most multi-family facilities and coin-operated Laundromats have gas water heat.

In November 2000, PSE began a pilot, offering a $50 rebate for efficient washers in coin-operated Laundromats with gas water heat. During 2001, a total of 92 rebates were paid for efficient washing machines in coin-operated Laundromats with gas water heat, for 42,780 Therms saved per year.

Duplex/Triplex Weatherization Pilot, Schedule 207 - Completed

The Duplex/Triplex pilot began in 1998, and with the concurrence of interested stakeholders, ended early in 2000. PSE was unable to demonstrate cost-effective energy savings. After two mailings to a total of 100 eligible customers and a number of site visits, no units qualified for weatherization. Customers did not qualify or decided not to participate for the following reasons:

- Existing insulation levels that exceeded the minimum criteria for the program
- Moisture and wood decay problems were present in a number of structures, where owners were not willing to spend additional money for corrective repairs or added venting in order to participate.

Owners and tenants of duplex and triplex structures remain eligible for PSE's other energy efficiency services.

Refrigerator Bulk Purchase Pilot, Schedule 208 - Completed

The Refrigerator Bulk Purchase Pilot, also initiated in 1998, encouraged the use of Energy Star qualified refrigerators in local housing authorities and other low-income housing. It had partial success in its first year but became unsustainable in its original design. The available targeted agencies could not generate sufficient long-term demand for refrigerator replacements and were resistant to abandoning traditional procurement channels.

In 2000, PSE enlisted the Washington State University Energy Program to verify estimated savings from the 1998 to 1999 demonstration pilot, and look for opportunities to develop a sustainable efficient refrigerator program. Results of the study confirmed that several housing authorities are now independently purchasing Energy Star qualified refrigerators, perhaps due to the influence of the pilot and regional Northwest Energy Efficiency Alliance efforts. However, use of Energy Star refrigerators to replace less efficient models is not universal. The study suggested that a regional approach to the replacement of old refrigerators, with local utility support, could have additional influence. PSE will continue working with opportunities that support regional efforts.

Commercial-Industrial Energy Efficiency Services, Schedules 250/205

Energy efficiency projects installed for the year 2001 under electric Schedule 250 and gas Schedule 205 will save 60,653 MWh and more than 1,632,000 Therms annually. Prompted by the energy crisis/news earlier in the year, PSE heavily promoted a "10 percent bonus" for retrofit projects, which could be completed by year-end. Year-end results reflect this year-long effort to motivate customers to receive this "limited-time-only" bonus before the year-end deadline. Projects completed in 2001 were 457.

Higher efficiency lighting continues to provide significant energy saving opportunities. Close to half (47 percent) of the installed retrofit measures involved lighting upgrades. PSE continues to maintain a contractor referral network, to help customers find qualified lighting installers. A third of the installed measures upgraded the efficiency of processes, including water heating and refrigeration measures. Nearly 20 percent of the measures upgraded efficiency for HVAC systems.

PSE is introducing more online service and tools available at www.pse.com for customers, with the goal of making it easier for customers to take action on energy management projects. Beginning in October 21,000 commercial customers began receiving time-of-use prices in monthly bills. These customers can view energy consumption on line, and get fast feedback about how changes to their operations can affect energy use. PSE is working to educate customers to take advantage of the power of this service as an energy management tool. The Company is also encouraging customers to review how they use energy with new on-line energy audits for businesses. These were introduced mid-year. The audits prioritize energy efficiency recommendations, and direct customers to PSE's grant and rebate programs for eligible measures. In addition, PSE is using a new e-newsletter for businesses as another way to help promote energy efficiency programs and services. In December PSE launched a reformatted version of this free newsletter service, sending it to 500 businesses via email. The new format provides convenient links to online services at the website.

Commercial-Industrial New Construction, Schedule 251

Funding is available for cost-effective energy savings measures in commercial new construction. PSE continues to assist customers to assure understanding and compliance with Washington State's Non Residential Energy Code (NREC). Commercial New Construction continues to be a challenging sector, especially if property is being developed for lease. Projects are most likely to come about if the owner is involved, and plans to occupy the facility with a direct financial interest in ongoing operating costs. Ten projects completed this year will save nearly 3,000 MWh annually. Two additional projects will save 3,489 Therms per year. It is unclear how broader economic conditions are going to impact PSE's ability to attract new program participants going forward.

Premium Efficiency Motors, Schedule 252

PSE works in coordination with the Northwest Efficiency Alliance (NEEA) motors program. Regional funding for NEEA's program has been extended to three years through 2003. The Company is anticipating follow-on customer leads from the NEEA program. Some of the latest regional activities include:

- A PSE-sponsored Motor Management Workshop held in December 2001. The seminar was very well attended and offered customers excellent information on motor management principles including a software demonstration.
- PSE customers are beginning to be contacted for potential field consultation services concerning motor management techniques.

- The “Windings” newsletter continues to be published and sent to customers every four months.

Resource Conservation Manager, Schedules 253/208

PSE offers the Resource Conservation Manager Service to any school district, public–sector government agency, or commercial or industrial customer, focusing on larger customers with multiple facilities. An RCM customer is one who employs (or contracts with) someone who has designated resource management responsibilities, including accounting for resource consumption and savings, (i.e., electricity, natural gas, water, sewer, and solid waste).

The RCM program is comprised of a “menu” of service features:

- A forum for resource managers to exchange information, ideas and techniques for controlling utility costs
- Assistance to customers in designing and implementing an RCM program and developing resource policy guidelines
- Aid in hiring a resource manager, including a salary guarantee or partial funding for a limited period to reduce the risk to customers
- A resource accounting system for tracking usage and analyzing and reporting savings relative to established baselines
- PSE billing data in electronic format to upload to the resource accounting system or the customer’s own resource database
- Training opportunities for resource managers and other customer personnel, such as custodians and maintenance staff
- Informational materials for classroom or building occupant use

Training and ongoing support is a key to a successful RCM program. PSE provides a forum for resource managers to share successes and challenges; and training activities that focus on technical and analytical skills, accounting tools, and project management. Private sector consultants can provide additional support to compliment resource manager skills, enhance productivity and increase cost effectiveness. In addition, some customer agreements include support from other utilities.

Program activities and results for 2001 are summarized below:

- RCM supported 46 customers, including 21 new customers. The RCM concept is catching on. Several utilities around the country have met, or have scheduled conference calls, to learn how to start an RCM program.
- RCM customers reported electric savings of approximately 24,600 MWh (2.8 average mega-watts) and natural gas savings of nearly 100,800 therms. One school district with an RCM program in place for only a year, saved over 2,000 MWh and more than 100,000 therms of natural gas for a total cost

savings of $220,000. This district had strong support from the school board and a paid full-time RCM position. Another school district, which has had an active RCM program for several years, made a concerted effort in 2001 and reduced electric and natural gas usage by 8.5 percent and 11.4 percent, respectively. Cost savings were over $200,000. This was in addition to exceptional savings achieved in prior years.

- Some customers find it difficult to support a full-time resource manager, due to budgetary restrictions. Several have had to let their resource managers go or reduce their hours. Continued support, by coordinating consultants to provide services such as utility cost tracking and facility control system tune-ups, enables these customers to find continued savings.
- Two networking/training meetings, attended by approximately 40 resource managers and RCM service providers, included tours of low-cost/no-cost conservation measures at Sea-Tac Airport in February and the Renton King County Wastewater Treatment Plant in May.

PSE's metering system, with Internet access to time-of-day usage, is useful for customers to diagnose building energy problems and control their usage. In 2002, training will include ways that RCM customers can maximize the value of this new system, in saving energy and money.

HB2247 requires school districts and state government facilities to conduct walk-through audits in 2002 to identify energy savings through O&M strategies and cost-effective investments. PSE will assist school districts with these efforts as part of the RCM services.

Northwest Energy Efficiency Alliance, Schedule 254

As a partner with the Northwest Energy Efficiency Alliance (NEEA), PSE contributes funding for regional programs, actively participates on the NEEA Board of Directors, and supports various related initiatives within the PSE service area. The Company believes that NEEA's market transformation initiatives will increase the availability and consumer acceptance of energy-efficient technologies and practices.

PSE programs that are directly related to regional NEEA activities include: Duct Systems Pilot, Schedules 203/204; Compact Fluorescent Lighting, Schedule 205; High Efficiency Clothes Washers, Schedule 206; Commercial-Industrial New Construction, Schedule 251; Premium Efficiency Motors, Schedule 252; Building Commissioning, Schedule 256; and Local Infrastructure/Market Transformation, Schedule 270.

NEEA reports energy savings of 61,424 MWh in first-year-savings for 2001 in PSE's Service area, representing a five-fold increase over previous annual periods (12,470 MWh in 2000, and 7,446 MWh in 1999). This increase is driven in part by expanded consumer purchasing of compact fluorescent lamps throughout the NW region in 2001, the result of several years of NEEA efforts to condition the market, and increased consumer interest in saving energy and reducing energy bills in 2001.

Expressed here only as first-year-savings, market transformation programs and activities are expected to produce greater savings over a longer period of time than those typically expected by mainstream utility programs. We are pleased with NEEA's success in securing funding participation by all of the major self-generating public and municipal utilities subsequent to their new contracts with the BPA, effective October 2001.

Detailed information on NEEA history, structure, funding, projects, reports, press-releases, proposals and more is available at NEEA's website at www.nwalliance.org.

Small Business Energy Efficiency, Schedule 255

PSE continued to expand service for small business customers in 2001. Small business customers are generally defined as facilities with less than 20,000 square feet or those served by electric Schedule 24 (under 50 kW demand).

Changes in 2001 included:

- The addition of a program manager and the dedication of energy advisors to handle energy-efficiency calls from commercial customers. Energy advisors are able to handle most small business inquiries. Larger customer or more complex energy-efficiency calls are referred to an energy management engineer for service typically covered under C/I Energy Efficiency Services, Schedules 250/205, or C/I New Construction, electric Schedule 251;
- Two new small commercial brochures: "Smart Lighting Options," and "Programmable Thermostats." These brochures support rebate programs and are available in paper format or online at www.pse.com;
- A free light switch and circuit breaker panel labeling kit -- a tool developed, in part, to serve the heightened energy awareness and supply concerns of 2001. Small business customers generally rely on manual forms of lighting control. The kit provides clear guidance;
- Revision of the lighting rebate to more specifically target and serve the needs of small business, increasing incentives and providing more supportive informational materials;
- Assistance to link the small businessperson with needed lighting expertise in the contracting and products-supply community.

These changes resulted in 8,935 customers served under Schedule 255, saving an estimated 1,320,300 kWh, more than twice the amount from the previous two years combined, and 56,800 Therms, up from only about 6,000 Therms from the previous two years.

PSE has developed the Personal Energy Management Center, which provides a central location for all customers to access PSE's online energy management tools. Once registered, customers have access to Energy Profile tools, calculators, a reference library, a product store and a contractor referral service. The PEM Center provides tools customers can use to understand their energy use, create an action plan and have access to resources to implement their energy plan. In addition, customers may subscribe to PSE's e-newsletter, which will be an on-going way to help customers stay engaged with managing their energy use.

Building Commissioning, Schedule 256

Energy management engineers have further developed working relationships with private sector building commissioning agents during the year, and attended the Building Commissioning Association (BCA) conference held in New Jersey during the first week of May 2001. While most building commissioning initiatives are large new construction projects, "retro-commissioning" of existing buildings also promise cost-effective opportunities for savings.

Commissioning projects facilitated by PSE may be "piggy-backed" with Schedules 250/205 or Schedule 251 funding for eligible measures. Building Commissioning program requirements include documentation of results and recommendations, as well as training of in-house operations staff.

Two commissioning projects were completed in 2001, achieving energy savings of 861,852 kWh of electricity and 3,164 Therms of natural gas. At year-end, six additional projects were already underway with projected savings of 650,000 kWh and 5,300 Therms.

Other activities included assisting the Washington State GA in developing a list of pre-approved commissioning providers for public building projects; and work with the NW Building Commissioning Collaborative Group. This group is presently focusing on incorporating commissioning into state building codes, and on tracking the efforts of northwest states to implement commissioning in public facilities.

LED Traffic Lights, Schedule 257

All prospective cities and county jurisdictions in PSE's service area have been contacted to promote energy-efficient LED traffic lights. In addition to energy savings, jurisdictions benefit from lower maintenance costs, improved safety, and reduced liability. Installation of LED traffic lights often requires adjustment of billing calculations for service without meters, under electric Schedule 57.

During 2001, one project for the Washington State Department of Transportation (WSDOT), which encompassed four counties, installed 996 red LED traffic lights, saving 734,610 kWh (or about $35,000) annually.

Beginning in July, PSE began offering $38 rebates for replacement of green 12 inch balls with green LED traffic lights, when installed in conjunction with red LED lights. The Association of Washington Cities assisted with an announcement in their October newsletter, reaching multiple personnel at 80 cities across the state, to increase awareness of the program. Several cities and additional WSDOT counties have projects underway and will be completing installation of red and green LED lights during 2002.

High Voltage/Optional Large Power Pilot, Schedule 258

With support from Industrial Customers of Northwest Utilities (ICNU), PSE has had good success in encouraging customer participation in the Schedule 258 program.

Eighteen projects have been completed through December 2001, with an energy savings of 12,493,000 kWh per year. Eight additional projects, now in construction and anticipated to be completed in the first quarter of 2002, will use the remaining allocated funds and have estimated savings of 7,627,000 kWh per year.

Total energy savings over the three-year life of the program is estimated to be 20,100,000 kWh, or 2.3 average mega-watts.

Local Infrastructure/Market Transformation, Schedule 270

PSE participates with or utilizes the services of many organizations to support the local delivery, management, and promotion of a broad range of energy efficiency programs. Financial support for these organizations is provided through Schedule 270, with spending capped at five percent of overall program budgets. Expenditures in 2001 were less than 1.5 percent of total electric program costs. Organizations currently supported by Schedule 270 include:

- E-Source
- Building Owners and Managers Association (BOMA)
- Puget Sound Chapter of ASHRAE
- Consortium for Energy Efficiency (CEE)
- Lighting Design Lab
- Electric League
- Northwest Energy Efficiency Council (NEEC)

Many of these organizations, particularly BOMA, NEEC and the Electric League were utilized on multiple occasions to present information directly to customers and key trade allies regarding best practices for responding to the energy crisis. Such venues involved both monthly membership and special meeting presentations coordinated to include joint information from all Puget Sound regional utilities.

Net Metering, Schedule 150

Schedule 150, Net Metering for Renewable Energy Services, became effective February 11, 1999. Subsequently, Schedule 150 was revised on June 8, 2000 in response to legislative action[3], which modified certain aspects of the net metering program. As revised, the schedule applies to customers who operate fuel cells or hydroelectric, solar or wind generators of no more that 25 kW. Service under this schedule is limited to a total of 4.5 MW of cumulative nameplate generating capacity, of which no less than 2.25 MW of cumulative nameplate generating capacity shall be attributable to net metering systems that use either solar, wind, or hydroelectric power as its fuel. Customer generation can be used to offset part or all of the customer-generator's electricity use under Schedules 7, 24, 25 or 29 of Electric Tariff G.

Two micro hydro customer-generators were interconnected in 1999; five solar photovoltaic systems began net metering in 2000; eight solar PV systems and one wind turbine generator were interconnected in 2001. One customer has a combination system, solar PV and wind turbine. The 15 customer-generator systems interconnected as of the end of December 2001 total 20.2 kW in maximum generating capacity.

Two hundred-twelve additional customers expressed an interest in net metering, and were provided with information regarding Schedule 150 and solar, wind, micro-hydro or fuel cell resources.

[3] On March 27, 2000, Engrossed House Bill 2334 relating to the definition of net metering systems and amending RCW 80.60.010, 80.60.020 and 80.60.040 was signed into law. The revised law became effective June 8, 2000.

Energy Efficiency Services
Program Results, January – December 2001
& Appendix B Projections for 2001

			January - December 2001								Appendix B Projections			
Elec Sch #	Gas Sch #	Service	Elec Units	Gas Units	Total Units	kWh Savings	Therm Savings	Electric Costs	Gas Costs	Total Costs	Total Units	kWh Savings	Therm Savings	Total Costs
150	na	Net Metering	8	-	8	-	-	$ 15,299	$ -	$ 15,299	-	-	-	$ -
200	206	Res. Energy Efficiency Services	79,869	66,900	146,769	4,872,009	358,046	$ 485,917	$ 390,865	$ 876,782	81,500	3,809,000	208,000	$ 450,000
201	203	Low-Income Retrofit	654	146	800	703,800	42,340	$ 786,066	$ 153,240	$ 939,306	550	700,000	56,000	$ 452,000
202	207	In Concert w/Environment	5,828	5,828	11,656	565,316	61,194	$ 300,285	$ 284,704	$ 584,989	10,000	582,000	42,000	$ 416,000
203	204	Residential Duct Systems Pilot	-	-	-	-	-	$ 56,693	$ 36,730	$ 93,423	400	360,000	19,200	$ 200,000
na	201	Gas Water Heater Rebate *	-	2,625	2,625	-	86,625	$ -	$ 113,605	$ 113,605	2,500	-	82,500	$ 80,000
205	na	Compact Fluorescent Lighting	2,490	-	2,490	1,351,075	-	$ 104,983	$ -	$ 104,983	2,000	600,000	-	$ 140,000
206	na	HiEfficiency Clothes Washers	71	92	163	56,800	42,780	$ 8,522	$ 5,414	$ 13,936	500	400,000	-	$ 37,000
207	na	Duplex/Triplex Retrofit Pilot	-	-	-	-	-	$ -	$ -	$ -	250	600,000	-	$ 200,000
208	na	Bulk Refrigerator Purchase Pilot	-	-	-	-	-	$ -	$ -	$ -	400	140,000	-	$ 20,000
na	na	Water Heater Control Pilot *	-	-	-	-	-	$ 34,487		$ 34,487	-	-	-	$ -
209	209	Low Income Customers *	na	na	na	-	-	$ 854,383	$ 145,616	$ 999,999	1,000	-	-	$ 1,000,000
250	205	C/I Energy Efficiency Services **	443	14	457	60,653,423	1,632,374	$ 8,854,943	$ 348,449	$ 9,203,392	300	16,800,000	62,500	$ 1,730,000
251	na	C/I New Construction **	10	2	12	2,989,404	3,489	$ 24,257	$ -	$ 24,257	15	1,500,000	-	$ 500,000
252	na	Premium Efficiency Motors	-	-	-	-	-	$ 2,299	$ -	$ 2,299	10	800,000	-	$ 75,000
253	208	Resource Conservation Manager	11	1	12	24,608,341	100,781	$ 70,830	$ 20,129	$ 90,959	25	19,000,000	316,600	$ 266,000
254	na	NW Energy Efficiency Alliance	na	na	na	61,424,000	-	$ 2,044,627	$ -	$ 2,044,627	-	-	-	$ 2,000,000
255	255	Small Business Energy Efficiency	6,749	2,186	8,935	1,320,300	50,858	$ 156,678	$ 85,745	$ 242,423	1,200	6,720,000	14,000	$ 270,000
256	na	Building Commissioning	2	1	3	861,852	3,164	$ 28,312	$ -	$ 28,312	10	500,000	-	$ 180,000
257	na	LEDTraffic Lights	996	-	996	734,610	-	$ 18,957	$ -	$ 18,957	5,000	2,000,000	-	$ 182,500
258	na	Hi Voltage/Opt Large Power Pilot	8	-	8	8,604,822	-	$ 759,583	$ -	$ 759,583	7	3,525,000	-	$ 1,175,000
270	na	Local Infrastructure&Mkt Trans	-	-	-	-	-	$ 182,812	$ -	$ 182,812	-	-	-	$ 150,000
		Total	**97,139**	**77,795**	**174,934**	**168,745,752**	**2,381,651**	**$ 14,789,933**	**$ 1,584,497**	**$ 16,374,430**	**105,667**	**58,036,000**	**800,800**	**$ 9,523,500**

* Line items for gas Schedule 201 Gas Water Heater Rebate, electric and gas schedules 209 Low Income Customers, and the Water Heater Control Pilot are not included in Rider and Tracker expenditures.

** Costs for Schedule 251 C/I New Construction are understated and costs for Schedule 250 C/I Energy Efficiency Services are overstated by $178,261 in 2001 due to a tracking error. A correction will be made in the first quarter of 2002.

Table 8.6: Program Results, January-December 2001

Energy Efficiency Services

Program Results, 1999 - 2001
& Appendix B Projections for 1999 – 2001

			1999-2001						Appendix B Projections			
Elec Sch #	**Gas Sch #**	**Service**	**Total Units**	**kWh Savings**	**Therm Savings**	**Electric Costs**	**Gas Costs**	**Total Costs**	**Total Units**	**kWh Savings**	**Therm Savings**	**Total Costs**
150	na	Net Metering	15	-	-	$ 50,716	$ -	$ 50,716	-	-	-	$ -
200	206	Res. Energy Efficiency Services	343,442	13,795,165	733,975	$ 975,757	$ 838,953	$ 1,814,710	244,500	11,427,000	624,000	$ 1,350,000
201	203	Low-Income Retrofit	2,143	2,464,700	126,320	$ 1,653,781	$ 502,437	$ 2,156,218	1,650	2,100,000	168,000	$ 1,356,000
202	207	In Concert w/Environment	32,072	1,723,593	244,024	$ 707,037	$ 718,174	$ 1,425,211	30,000	1,746,000	126,000	$ 1,248,000
203	204	Residential Duct Systems Pilot	17	15,300	-	$ 167,396	$ 59,404	$ 226,800	825	780,000	36,300	$ 490,000
na	201	Gas Water Heater Rebate *	8,268	-	272,844	$ -	$ 357,109	$ 357,109	7,500	-	247,500	$ 240,000
205	na	Compact Fluorescent Lighting	7,665	3,374,006	-	$ 202,349	$ -	$ 202,349	4,500	1,350,000	-	$ 366,000
206	na	HiEfficiency Clothes Washers	291	142,400	52,440	$ 33,810	$ 11,042	$ 44,852	1,500	1,200,000	-	$ 111,000
207	na	Duplex/Triplex Retrofit Pilot	-	-	-	$ 10,981	$ -	$ 10,981	794	1,907,000	-	$ 650,000
208	na	Bulk Refrigerator Purchase Pilot	-	-	-	$ 25,735	$ -	$ 25,735	1,200	420,000	-	$ 60,000
na	na	Water Heater Control Pilot *	-	-	-	$ 34,487	$ -	$ 34,487	-	-	-	$ -
209	209	Low Income Customers *	-	-	-	$ 2,131,261	$ 868,224	$ 2,999,485	3,000	-	-	$ 3,000,000
250	205	C/I Energy Efficiency Services **	648	103,992,735	2,594,429	$ 11,697,104	$ 538,839	$ 12,235,943	900	50,400,000	187,500	$ 5,190,000
251	na	C/I New Construction **	31	8,947,770	3,489	$ 56,780	$ -	$ 56,780	40	4,500,000	-	$ 1,500,000
252	na	Premium Efficiency Motors	-	-	-	$ 16,498	$ -	$ 16,498	23	1,840,000	-	$ 190,000
253	208	Resource Conservation Manager	54	43,553,919	954,692	$ 271,298	$ 79,399	$ 350,697	25	40,800,000	679,800	$ 699,000
254	na	NW Energy Efficiency Alliance	-	81,340,000	-	$ 6,599,563	$ -	$ 6,599,563	-	-	-	$ 6,700,000
255	255	Small Business Energy Efficiency	9,680	1,937,475	56,842	$ 216,124	$ 101,164	$ 317,288	3,600	20,160,000	42,000	$ 810,000
256	na	Building Commissioning	6	1,546,672	44,964	$ 45,617	$ -	$ 45,617	22	1,320,000	-	$ 385,000
257	na	LEDTraffic Lights	1,844	1,306,505	-	$ 51,872	$ -	$ 51,872	12,500	5,020,000	-	$ 452,500
258	na	Hi Voltage/Opt Large Power Pilot	16	12,437,939	-	$ 1,099,288	$ -	$ 1,099,288	21	8,550,000	-	$ 2,850,000
270	na	Local Infrastructure&Mkt Trans	181	-	-	$ 362,514	$ -	$ 362,514	-	-	-	$ 450,000
		Total	**406,373**	**276,578,179**	**5,084,019**	**$ 26,409,968**	**$ 4,074,745**	**$ 30,484,713**	**312,600**	**153,520,000**	**2,111,100**	**$ 28,097,500**

* Line items for gas Schedule 201 Gas Water Heater Rebate, electric and gas schedules 209 Low Income Customers, and the Water Heater Control Pilot are not included in Rider and Tracker expenditures.

** Costs for Schedule 251 C/I New Construction are understated and costs for Schedule 250 C/I Energy Efficiency Services are overstated by $316,842 for the three year period due to a tracking error. A correction will be made in the first quarter of 2002.

Table 8.7: Program Results, 1999 – 2001

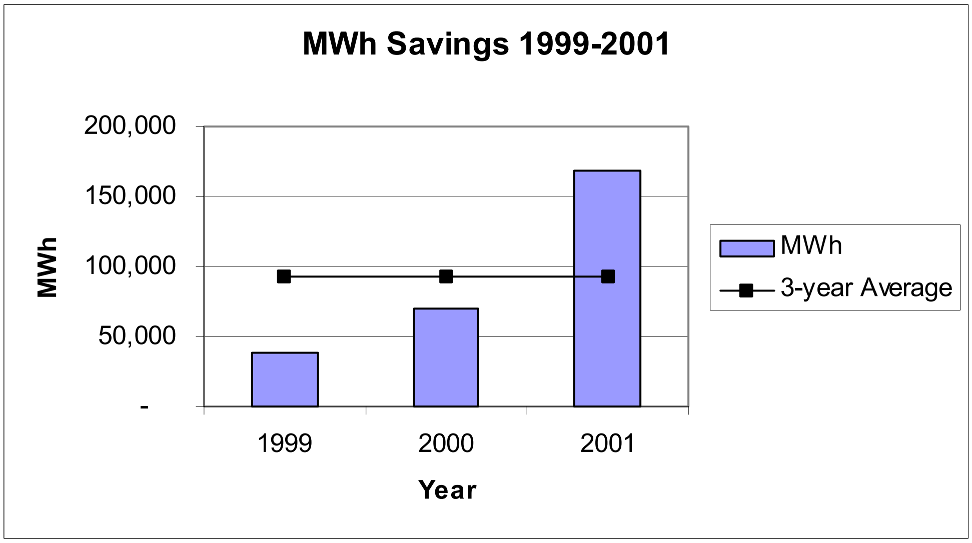


Figure 8.13: MWh Savings, 1999 – 2001

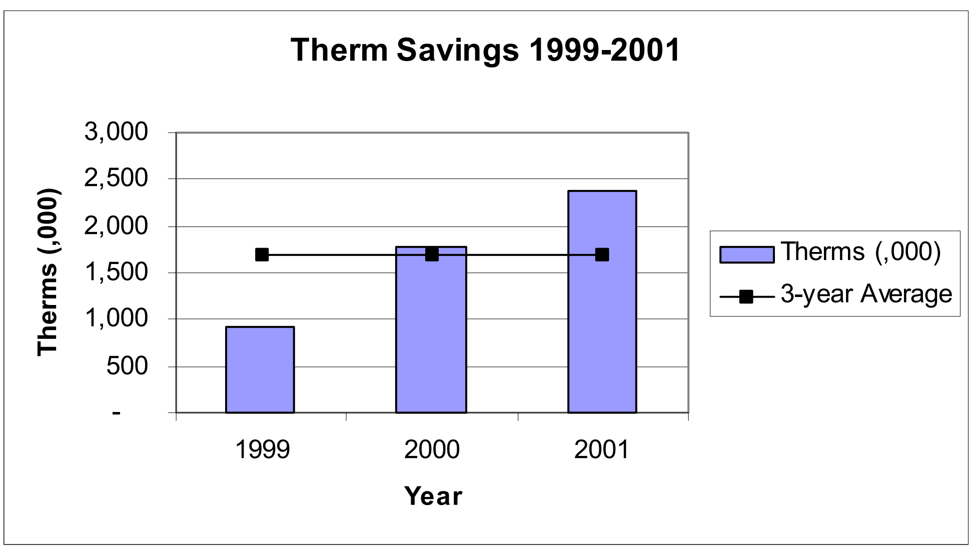


Figure 8.14: Therm Savings, 1999 – 2001

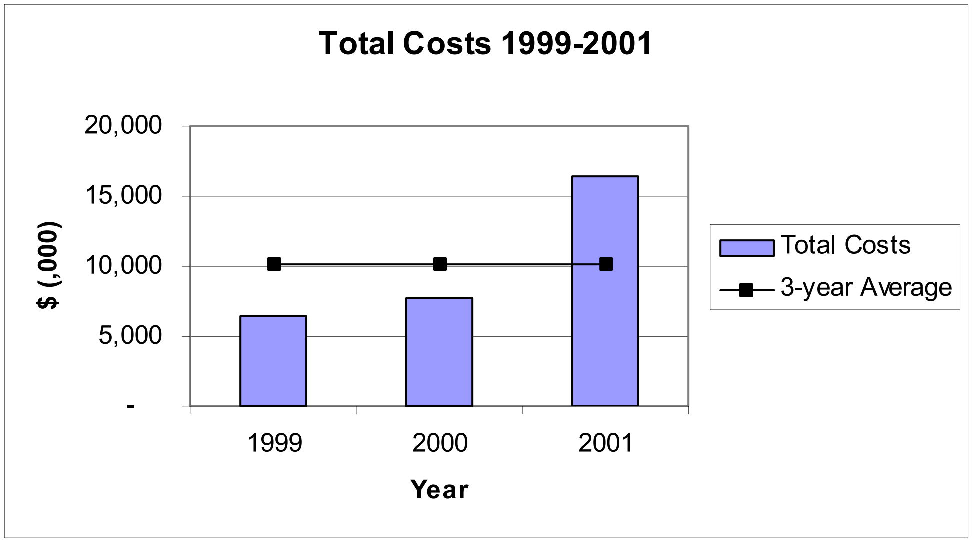


Figure 8.15: Total Costs, 1999 – 2001

PEM Results

The following Figures 8.16 through 8.21 provide insight into the value PSE is receiving from the PEM effort.

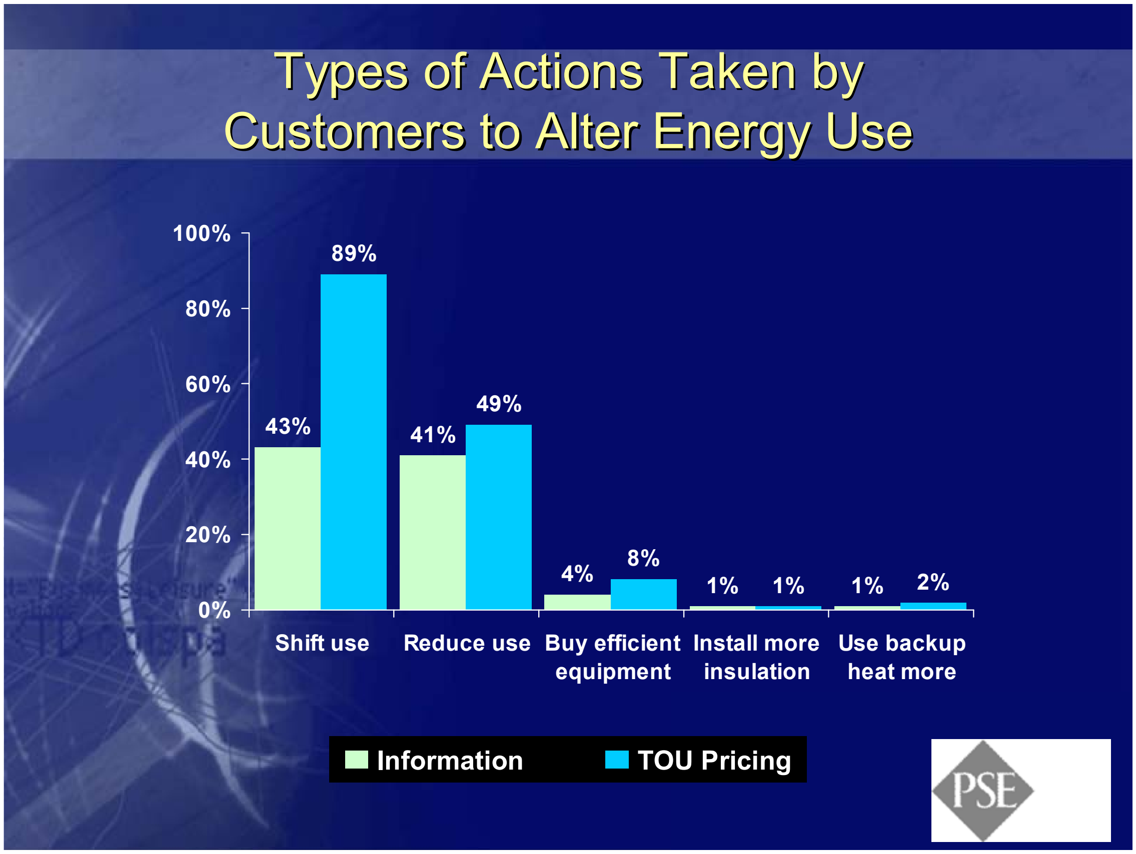


Figure 8.16 Types of Actions Taken by Customers to Alter Energy Use

Energy use was both shifted and reduced through simply providing information about conservation at about the same magnitude. However, there was considerable load shifting with the introduction of the Time-of-Use Rates. Note that there was some measurable progress made in the purchasing of high efficient equipment through this process as well. Twice the impact was achieved in the buying of efficient equipment under the use of TOU pricing, i.e., four to eight percent.

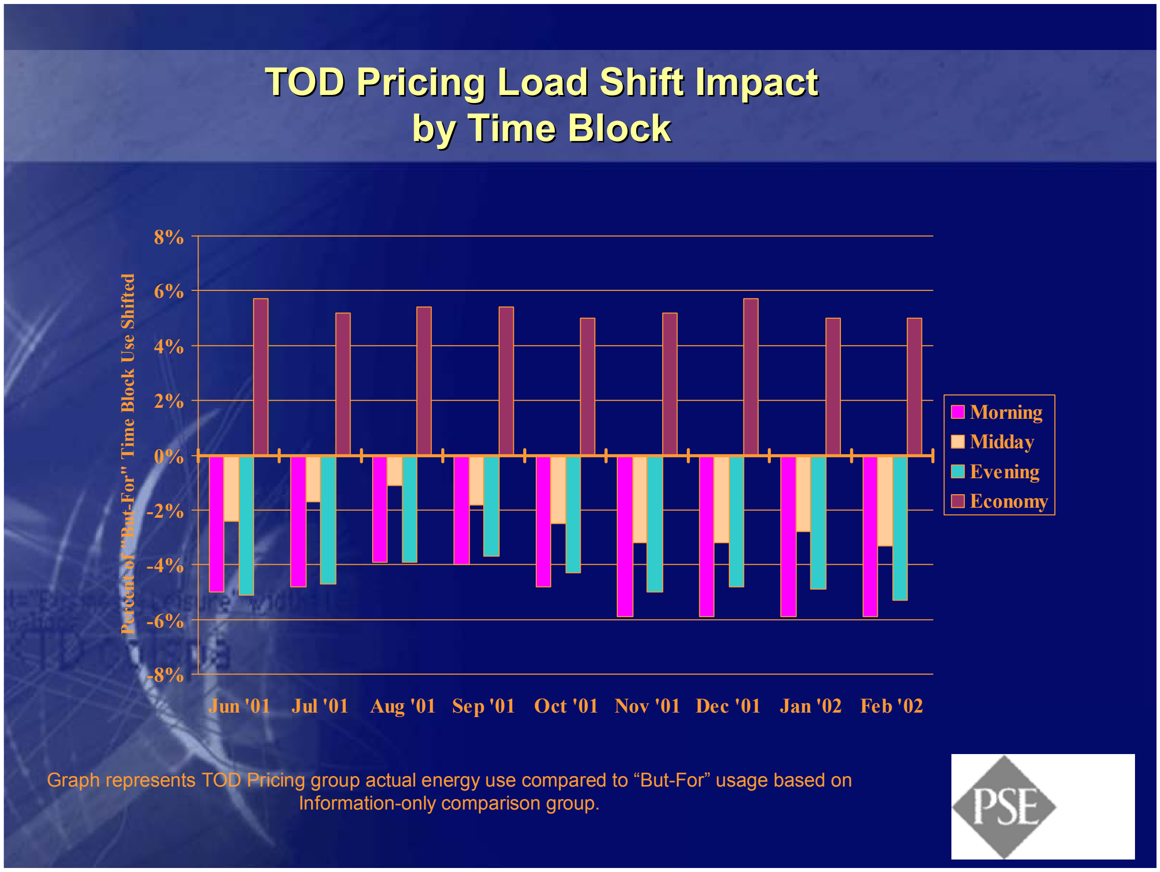


Figure 8.17: TOD Pricing Load Shift Impact by Time Block

Figure 8.17 graphically depicts the percentage shift from the Morning, Midday and Evening hours to the "Economy" time period. This represented a considerable savings to PSE in load shift.

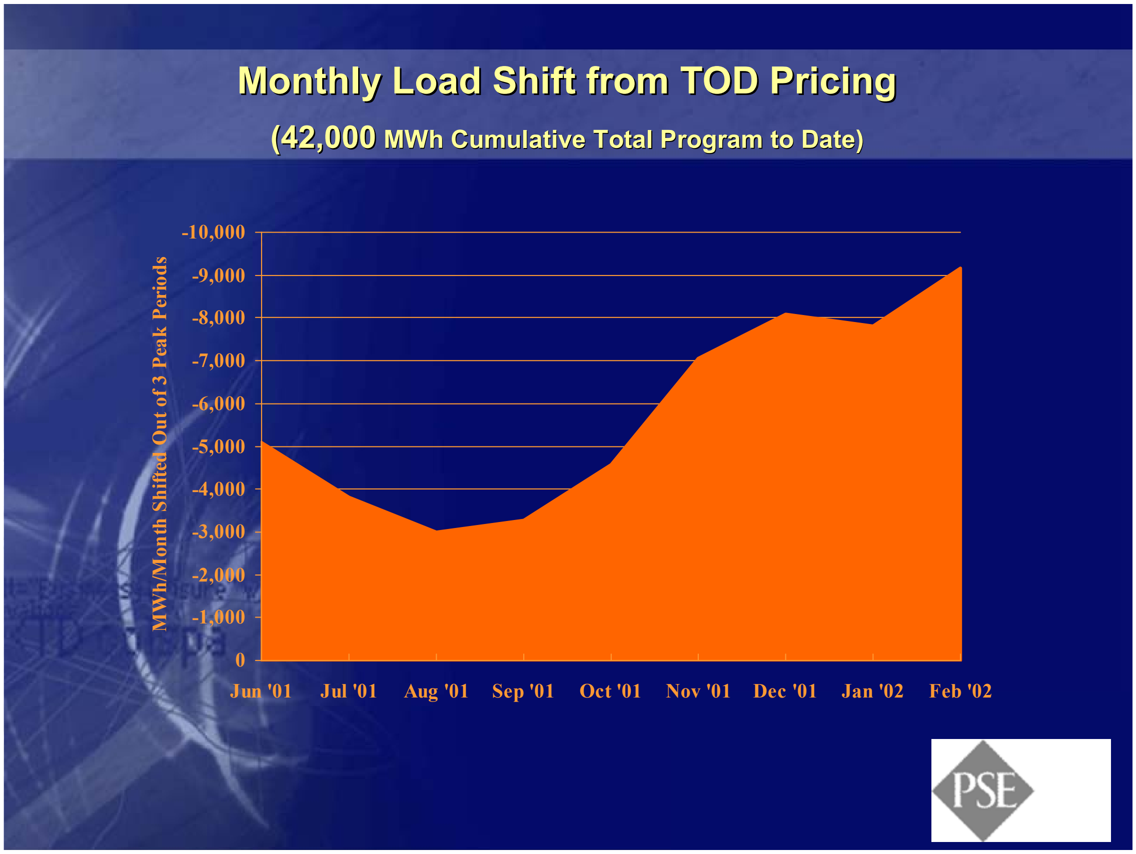


Figure 8.18: Monthly Load Shift from TOD Pricing

Figure 8.18 shows the increasingly large amount of energy that is being shifted to the off-peak time periods.

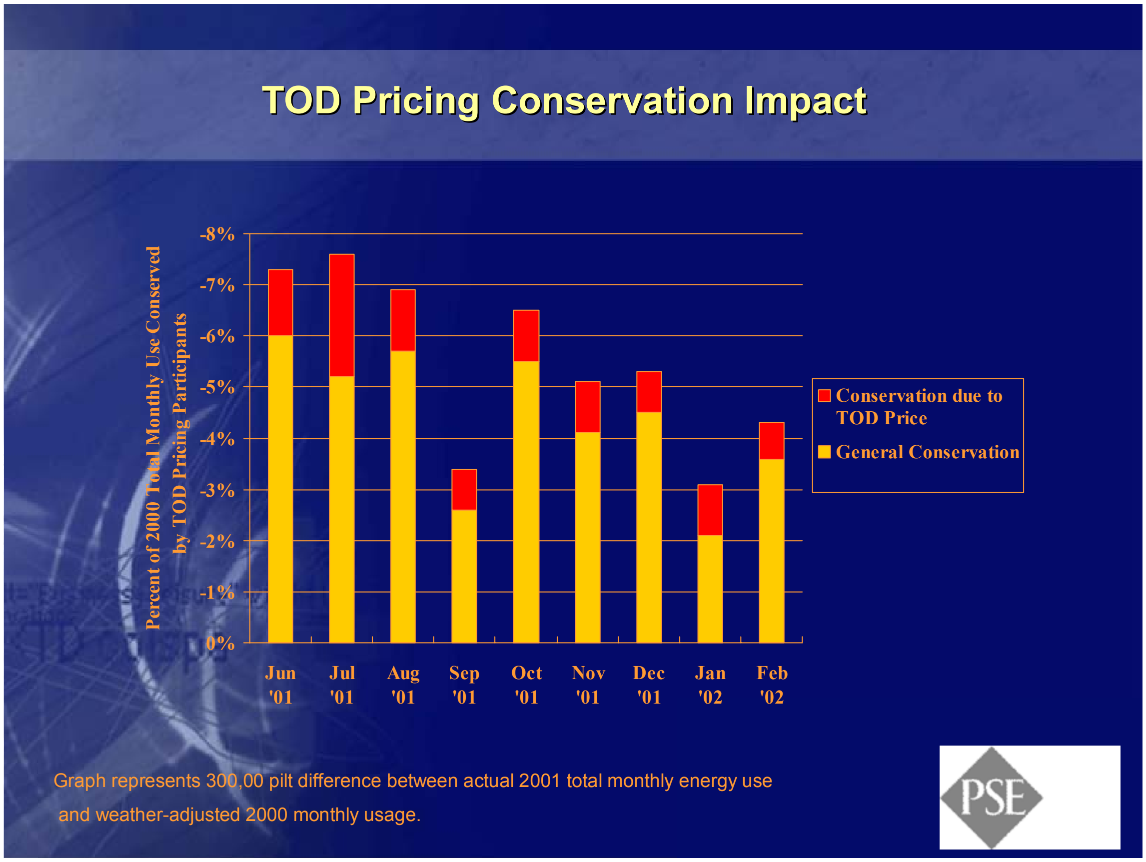


Figure 8.19: TOD Pricing Conservation Impact

In Figure 8.19, PSE has illustrated the amount of overall conservation that is attributable to the Time-of-Use Rates offered as compared to general conservation measures.

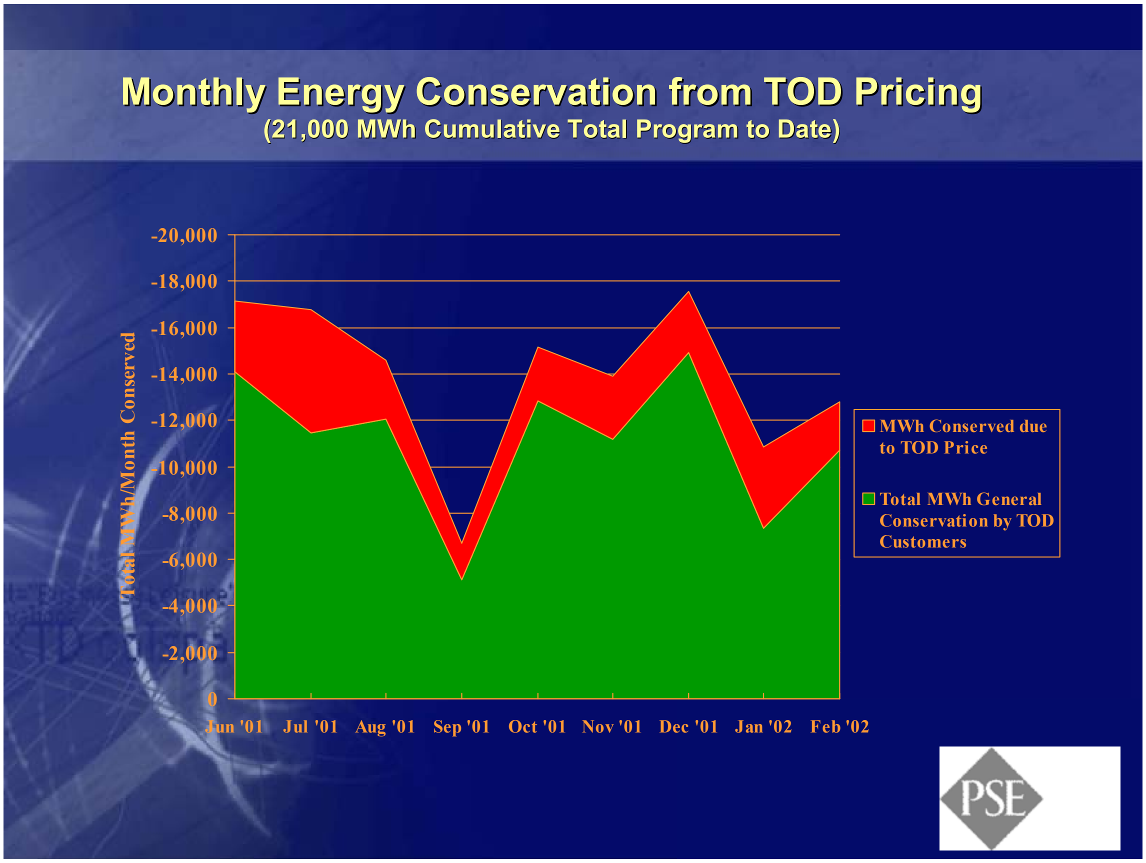


Figure 8.20: Monthly Energy Conservation From TOD Pricing

Figure 8.20 shows the reduced amount of energy conservation in September, attributable to the September 11 attack on the World Trade Towers. It was felt that people were "nesting" at home, rather than traveling.

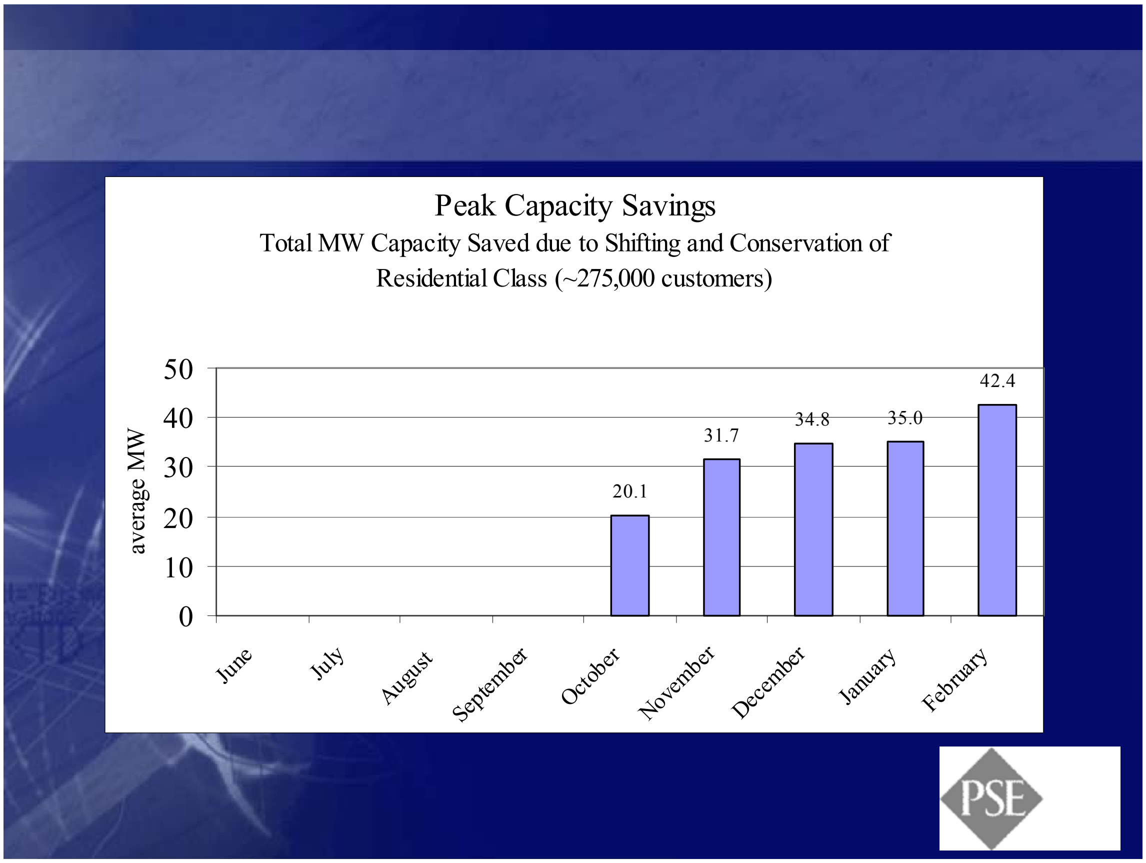


Figure 8.21: Peak Capacity Savings (2001-2002)

Figure 8.21 shows the increasing amount of electrical energy demand being saved by their PEM initiative.

RECOMMENDATIONS

Average Substation Utilization Level

Salt River Project conducted extensive work in the area of load forecasting. PacifiCorp is currently moving toward a more active role in development of a load-forecasting model that should enable better forecasting. The current status on how aggressively this is being pursued is unknown. This is mentioned since the accuracy of load forecasting is directly tied to the ability to increase the planned average substation utilization levels.

SRP has extensive data and research relative to how high the substation utilization metric should be set to both minimize asset investment and provide adequate customer service. While the weather conditions, geography and customer classifications are differing from those along the Wasatch Front, they did find the average substation utilization level could not exceed 88 percent of nameplate rating – or 70 percent of the emergency rating. In the process of collecting this information, SRP had loaded substations beyond their current targeted utilization level and received adverse customer impact.

PacifiCorp will continue to operate at higher and higher average substation utilization values, which is appropriate *only* as the load forecasting accuracy correspondingly rises. An actual growth rate of ten percent, when only four or five percent is forecasted, would create much turmoil (the need for many new facilities and more skilled labor to perform the installations) at a high average substation utilization level.

In the year 2001, the average substation utilization level was 62 percent. In the event they follow their current capital investment initiatives, by 2006 the Wasatch Front substations will be loaded to an average substation utilization level of 76 percent. Such actions should be undertaken with restraint. This may represent a sufficient amount of time for PacifiCorp to increase their load forecasting reliability.

Demand Side Management Programs

PacifiCorp had implemented a demand side management program that allowed for a reduction in a customer’s energy bill of 20 percent or 10 percent if they reduced their consumption respectively by 20 percent or 10 percent of the previous year’s usage. The results from this action are dependent upon weather conditions and require weather normalization techniques to determine it’s overall impact on energy savings and demand reduction. However, it had a favorable response from their customers, who in Utah, participated at a rate of about 25 percent.

It is recommended that PacifiCorp consider a more aggressive position on Demand Side Management programs. The examples set by Puget Sound Energy have achieved measurable savings, both in shifting demand and reducing overall energy consumption.

This has begun with the existing RFP that provides for a pilot project to obtain direct control of residential air conditioners. The details of which were previously discussed.

Distributed Generation Opportunities

It is recommended that PacifiCorp examine promoting the use of distributed generation among its Commercial and Industrial customers. This entails such activities as: (1) the analysis of where/if DG would be most effective on their distribution system; (2) the determination of the tangible and intangible economic value of DG to PacifiCorp at those locations; (3) the method that DG would be controlled, if controlled centrally for economic or area dispatch; (4) the creation of rates that would be incentives for customers to install DG at their premise; and, (5) the development of a marketing/communication plan for full rollout and implementation.

9 CONCLUSION

The following conclusions are recommendations that are presented to the Utah Department of Public Utilities and the Public Service Commissioners as actionable items for PacifiCorp to either undertake within their organization, or monitor, report, or present in some manner to the DPU staff or Commissioners. Some actions also impact upon the DPU.

RECOMMENDATION #1:

Continue to Improve Load Forecasting Abilities[1]

1. Continue with the current direction of improving load forecasting abilities within PacifiCorp.
2. Consider expanding on the current ABB forecasting knowledge base. This can be accomplished by assuming the function in-house by PacifiCorp (training on the use of the ABB FORESITE load forecasting tool would be required) or by outsourcing the work responsibility.
3. Consider alternative methodologies that lead to the same results. In the latest discussions, PacifiCorp indicated they are moving in such a direction, whereby these efforts would include such items as:
    a. Conducting additional end-use research to determine when saturation occurs
    b. Implementing a load data warehouse
    c. Collecting, storing, assimilating, and feeding the load information into other applications
4. Improve Community Relations and reinforce communication flow through the PacifiCorp plan currently under development. The action items would include such items as:
    a. Conducting an Economic Summit with the Governor's office - planning session, essentially a round table discussion on what has been done on the topic of load or growth forecasting.
    b. Working in cooperation with Utah League of Cities and Towns (members of the 50 public agencies they talked to earlier) to collect growth and development data for PacifiCorp. This concept would be introduced during a monthly meeting.

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[1] Reference Section 5 – Load Forecasting Analysis

c. Presenting Community Information meetings that would include: (1) basic Electric Utility information; (2) how load forecasting is accomplished; and (3) how the communities can help PacifiCorp perform better planning by having more accurate information.

Recommendations to DPU

	Specific Options	Outcome
A.	Report/present PacifiCorp's progress on using ABB FORESITE Load Forecasting Software or their alternative solution(s). The purpose of the presented material is to demonstrate increased competency in load forecasting. Report or present to DPU staff by August 1, 2002 and follow up with update reports on January and July 2003.	Increased confidence in planning asset investments for reliable service.
B.	Provide listing of Capital T&D Budget in January 2003 listing the 2003 and 2004 budget authorizations. Future reports are at the discretion of the DPU.	Ensure authorizations are continued to be invested in asset base.

RECOMMENDATION #2:

Establish Load Forecasting Benchmarks[2]

1. Establish benchmarking criteria to determine how closely load forecasts match to actual loads, which is the only manner of knowing load forecasting accuracy is improving.
2. Track on a winter and summer basis, with most weight given to the summer peak loading conditions.
3. Actual versus forecasted loads could be discussed at quarterly meetings held between the DPU staff, Commissioners, and PacifiCorp or at other such forums.

[2] Reference Section 5 – Load Forecasting Analysis

Recommendations to DPU

	Specific Options	Outcome
A.	Present a methodology of tracking the accuracy of Winter & Summer Actual versus Forecasted Loads, by select geographic regions.	Ensure PacifiCorp possesses capability to perform accurate load forecasting that leads to reliable service.
B.	Any reports provided by PacifiCorp should include historical trend analysis; targeted metrics; and detailed explanation of results.	There should be continuing improvement in forecasting accuracy – continually measured.

RECOMMENDATION #3:

Strengthen Load Growth Projections Emanating from Field Offices[3]

1. Increase effectiveness of the Asset Management organizational structure through improved internal communication processes.
2. Provide additional training for Field Engineer positions to increase confidence level in data received by the Asset Management department.
3. Expand use of field personnel to collect land use information for the ABB FORESITE tool (or other selected planning tool) from public agencies along the Wasatch Front.

Specific Recommendations to DPU

	Specific Options	Outcome
A.	Present or demonstrate the incorporation of public agency and developer information into the ABB FORESITE tool or other chosen forecasting tool/model.	Ensure that known land use and population information is incorporated into the load forecasting model.

[3] Reference Section 6 – Distribution Planning

RECOMMENDATION #4:

Pursue Distribution Automation Opportunities[4]

1. Expand Distribution Automation (DA) in the PacifiCorp service territory.
2. Create standards for distribution automation utilization in their planning process:
    a. Establish a communication protocol
    b. Device sensing and control selection
    c. Determination of data collected and how used
    d. Economic evaluation of sectors to be automated
3. Expand reliability programs as needed (currently the worst five feeders are corrected as part of Performance Standards one through four that identifies the worst feeders over five years). Basically, this program (DA) is a tool to get there.

Recommendations to DPU

	Specific Options	Outcome
A.	Disclose and substantiate Standards created for Distribution Automation as adopted by PacifiCorp. Continue current reporting requirements.	Ensures that DA is used appropriately – to increase reliability and planning effectiveness.

RECOMMENDATION #5:

Develop Formal Feeder Switching (Breakdown) Analysis Sheets for Outage Restoration Work[5]

1. Develop formal documentation on substation and feeder switching during outage contingencies (Salt Lake City area has these due to the recently held Olympic events).
2. Make updated documents available to system operations dispatchers for power restoration (it's a function within CADOPS that is not currently used).

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[4] Reference 6 – Distribution Planning

[5] Reference Section 6 – Distribution Planning

Recommendations to DPU

	Specific Options	Outcome
A.	None.	

RECOMMENDATION #6:

Improve Planning Process for Optimal Timing of Asset Investment Installations[6]

1. Increase construction lead-times to allow adequate time for planning study and project construction.
2. Authorize construction for new substation capacity additions at least 18 months prior to the need of the project.

Specific Recommendations to DPU

	Specific Options	Outcome
A.	None	

RECOMMENDATION #7:

Plan for Minimizing Outage Restoration Duration[7]

1. Review the outage restoration procedures relative to the 14-hour maximum outage criteria for mobile substations (typical numbers are six to eight hours).
2. Examine the outage reporting process to the DPU to ensure sufficient information is being secured from PacifiCorp.

[6] Reference Section 6 – Distribution Planning

[7] Reference Section 6 – Distribution Planning

Recommendations to DPU

	Specific Options	Outcome
A.	Analyze current outage reports to determine if a 14-hour mobile substation installation time is acceptable. Consider customer survey.	Possible directive to PacifiCorp to reduce the maximum outage duration as currently designed.
B.	Review the number of times that Mobile Substations have been used in outage conditions and the typical outage duration realized.	

RECOMMENDATION #8:

File for the Creation of an Undergrounding Surcharge by Franchise in Utah[8]

1. Propose an Underground surcharge rate for customers within underground franchises to keep rates and benefits to all customers equitable.
2. Cities establish underground districts allowing PacifiCorp to collect a sufficient surcharge from customers within that city.
3. Funds will be used for undergrounding lines (difference of underground to overhead for new lines)
4. PacifiCorp could advance for insufficient funds or finance the costs over a specified period of time.

Recommendations to DPU

	Specific Options	Outcome
A.	Submit the Undergrounding Surcharge Rate and Rules for approval by regulators.	Increased customer satisfaction.

[8] Reference Section 6 – Distribution Planning

RECOMMENDATION #9:

Review Field Employee Staffing Levels[9]

1. Review the staffing level of the designers and field engineers in the areas where the load is growing at a faster than average rate.
2. Consider increasing these staffing levels, since the growth is projected to continue at the current rate for the next few years (and this position requires at least four years of special training to be proficient in the required skills).
3. The work may be outsourced as well.

Recommendations to DPU

	Specific Options	Outcome
A.	None.	

RECOMMENDATION #10:

Migrate to One GIS Mapping System[10]

1. Accelerate migration from multiple mapping systems, including AutoCAD and ABB FEEDER-ALL, to one GIS mapping system for the purpose of:
    a. Eliminating redundant data entry
    b. Improving mapping accuracy
    c. Increasing safety for employees and the public
    d. Reducing outage duration
    e. Increasing service reliability
2. PacifiCorp is redoing the whole process. The currently used design software (RCMS) will be replaced with a graphical estimation tool now under evaluation.

Recommendations to DPU

	Specific Options	Outcome
A.	None.	

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[9] Reference Section 7 – Distribution Engineering

[10] Reference Section 7 – Distribution Engineering

RECOMMENDATION #11:

Provide Tighter Integration into SAP[11]

1. Accelerate integration of the cost estimating, mapping, and tracking programs into SAP for the purpose of:
   a. Optimizing work processes by decreasing multiple data entry
   b. Making better decisions of the scheduling of employees
   c. Making better decisions regarding the utilization of assets.
2. PacifiCorp plans to issue future RFP for providing the overall design authority.

Recommendations to DPU

	Specific Options	Outcome
A.	None.	

RECOMMENDATION #12:

Monitor the Average Substation Utilization Level[12]

1. Salt River Project research suggests the average substation utilization level for their area should not exceed 88 percent of transformer nameplate rating – higher levels proved to significantly reduce customer satisfaction.
2. Regional areas of like characteristics should be studied to determine the appropriate average substation utilization levels in the PacifiCorp service territory.
3. PacifiCorp must create and rely on accurate load forecasting models in order to achieve the optimal average substation utilization levels. Improvements should be measurable.
4. Determine how Salt River Project information is or is not applicable to PacifiCorp. SRP has a homogeneous service territory, unlike PacifiCorp. Simply increasing the average substation utilization levels without analysis is opening PacifiCorp to the same rise levels previously experienced by SRP that resulted in unsatisfied customers.

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[11] Reference Section 7 – Distribution Engineering

[12] Reference Section 8 - Benchmarking

Recommendations to DPU

	Submit Options	Outcome
A.	Present results of study or research report that identifies PacifiCorp's targeted average substation utilization levels by region.	Maintain or improve current service reliability, while achieving appropriate levels of average substation utilization by region.

RECOMMENDATION #13:

Increase Demand Side Management and Conservation Programs[13]

1. Adopt a more aggressive position (direct load control) on Demand Side Management programs to shift and manage existing load to improve reliability and better utilize assets. This includes devising a Residential Air Conditioner direct load control program, (which is currently being addressed by PacifiCorp).
2. Determine and implement (including appropriate incentives with cost recovery) least cost conservation programs to reduce overall demand levels.

Recommendations to DPU

	Submit Options	Outcome
A.	Submit for approval the Demand Side Management programs and associated rate structures PacifiCorp desires for direct load control.	Demand Side Management use enables shifting of existing load for reduced energy costs and increased asset utilization.
B.	PacifiCorp submits conservation programs with required cost recovery mechanism for approval by regulators.	Conservation measures introduced will reduce energy consumption, reduce emission and defer asset investments.

[13] Reference Section 8 - Benchmarking

RECOMMENDATION #14:

Investigate Distributed Generation Opportunities[14]

1. Promote economically viable use of distributed generation among its C&I customers (and company-owned DG), which involves:
    a. Analysis of where DG would be most effective
    b. Determination of the tangible/intangible benefits of DG to PacifiCorp
    c. Method that DG would be controlled centrally for economic or area dispatch
    d. Creation of rate incentives for customers to install DG at their premise
    e. Development of a marketing and communication plan for full rollout and implementation

Recommendations to DPU

	Submit Options	Outcome
A.	Deliver a report or presentation on the existing PacifiCorp Distributed Generation Strategy.	Better asset utilization, improved reliability, and improved customer satisfaction.

[14] Reference Section 8 - Benchmarking

DEVELOPMENTS IN BEST PRACTICE REGULATION: PRINCIPLES, PROCESSES, AND PERFORMANCE

By Sanford Berg[1]

The art of regulation involves establishing rules that allocate value to consumers and suppliers in such a way as to maintain incentives for the firm to create value, while promoting political legitimacy in the eyes of consumers and other stakeholders.

This article provides an overview of developments in best-practice regulation. It identifies issues that investors and executives consider when determining infrastructure activities in emerging markets. In an earlier article in this journal (Berg, 1998), the author focused on two basic regulatory design issues: the behaviors that should be regulated, and mechanisms for developing and enforcing rules. Both fall under the category of regulatory incentives. Here, the emphasis is on regulatory governance: how new regulatory agencies are insulated from ongoing political pressures, while utilizing processes that promote participation, transparency, and predictability. Standard & Poor's and other ratings agencies are beginning to evaluate the regulatory environments facing electricity firms operating around the world. Such information becomes an important determinant of risk factors to be applied to each company's expected net cash flows.

Thus, each country needs to resolve issues related to the design and operation of regulatory institutions. Principles and processes matter because potential investors are looking for signs of regulatory independence and signals that policies are based on a comprehensive analytical framework rather than on the whims of individuals.

The Public Utility Research Center (PURC) has worked on this topic on an intensive and regular basis. In collaboration with the World Bank, we have conducted seven international training programs on Utility Regulation and

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[1] Sanford Berg is Director, **Public Utility Research Center**, Warrington College of Business, University of Florida. An earlier version of this article was presented at the *Incentive Regulation and Overseas Development Conference (November 1999 in Sydney, sponsored by the Australia Competition and Consumer Commission).*

Strategy over the past three years. Over 600 regulators and managers from 90 countries have come to Florida to participate in the two-week course. We have learned a great deal about the principles of regulation and about the regulatory process. Although I cannot report that we have the *definitive* classification scheme which allows us to rank all regulatory commissions on the basis of well-defined (and quantifiable) criteria – and, in fact there is no "ideal" commission, since organizational design depends on the institutional context (Levy and Spiller, 1994) – I nevertheless will propose a criterion from an economist's perspective.

Recently, Australia's Utility Regulators Forum (1999) generated a discussion paper of "Best Practice Utility Regulation" prepared as part of a program to promote the exchange of ideas regarding regulatory activities. The authors identified nine *best practice principles*:

1. Communication (information to stakeholders on a timely and accessible basis)
2. Consultation (participation of stakeholders in meetings)
3. Consistency (across market participants and over time)
4. Predictability (a reputation that facilitates planning by suppliers and customers)
5. Flexibility (by using appropriate instruments in response to changing conditions)
6. Independence (autonomy—free from undue political influence)
7. Effectiveness and Efficiency (cost-effectiveness emphasized in data collection and policies)
8. Accountability (clearly-defined processes and rationales for decisions, with appeals)
9. Transparency (openness of the process)

These principles were then embodied in *best practice processes*, as problems are identified and addressed in a systematic manner.[2] Finally, the third component emphasized in the discussion paper related to *best-practice organizations*: the role, resources, and structure of the agency. The staff expertise for making decisions and clarity of responsibilities (within and among government entities) were important aspects of this third component.

[2] Stern and Holder (1999) use a similar framework for appraising regulatory systems. They emphasize three principles that relate to institutional design (the formal elements of regulation): (1) Clarity of Roles and Objectives; (2) Autonomy; and (3) Accountability. They identify three areas related to regulatory processes (informal accountability): (4) Participation; (5) Transparency; and (6) Predictability. The six criteria are used to rate agencies in six Asian nations.

The government document represents a good overview of the institutional design and regulatory process issues. Lawmakers must address them when establishing or evaluating a regulatory agency. However, the framework needs to be extended to include *sector performance* as the *ultimate* indicator of regulatory performance. If good regulation only involves filling out a checklist of agency qualities, then organizations with law-abiding, well-intentioned people ought to be able to score high on indicators reflecting each of the nine principles. In addition, the regulatory process can reflect those principles. Yet if firms in the sector are not performing in a manner that matches standards set by similar firms in other countries, then how can that regulation be "best practice"? Somehow, regulatory outcomes must be factored into the evaluation, and both relative and absolute levels of sector performance can be regarded as outcomes of interest to customers and investors. If consumers are being denied valued new services available to those in other countries, then the principles and processes will not be adequate indicators of performance.

Fortunately, the conflict is more apparent than real. These regulatory inputs (principles, processes, and organization) will tend to promote investments and managerial activities that enhance actual industry performance. However, if the substance of regulatory strategies and the implementation of associated policies are inconsistent with strong sector performance, then the benchmarking exercise needs to recognize this policy failure.

For simplicity, let performance consist of five elements:

1. Productivity advance (reflecting cost containment and adoption of new technologies)
2. New service introductions
3. Returns to investors commensurate with the risks they bear
4. Prices that reflect minimum incremental costs
5. Expansion of basic services to particular customer groups

Countries with high performance in energy, water, and telecommunications sectors will generally also have good regulatory performance - as defined in the Regulators Forum document or the NERA study by Stern and Holder. The associated agencies will have met the checklist of principles. In addition, they will tend to have processes that promote credibility with investors and legitimacy with consumers. Finally, successful agencies have organizational designs that enhance efficiency in the sector and the economy as a whole.

Thus, a key indicator of regulatory performance is sector performance. The number of studies, cases decided, and rules promulgated are regulatory inputs.

However, the fundamental regulatory output is industry performance. Benchmarking looks at both inputs and outputs. Of course, sector performance is also dependent on general economic conditions and institutional features of the economy (including an independent judiciary and political restraint). Nevertheless, if the study of “best practice” focuses on principles and procedures rather than market outcomes, we will have a very limited perspective on what really matters.

I. Regulatory Governance and Performance

The task of assessing the merits of specific infrastructure regulatory policies is complicated by the intricate relationships among key variables. Some of these relationships are depicted in Figure A.1. The two boxes to the far left represent some of the factors that influence a government's choice of infrastructure policy. *Experience* refers to local, national, and international experience with infrastructure regulatory policies. Industry performance under regulatory regimes in different nations provides lessons that affect agency design and incentive policies. The *Institutional Conditions* box depicts how other factors influence the design of regulatory agencies. These factors include the strength and independence of a country's judicial system, the nature and stability of the country’s political system, the autonomy of regulatory officials, resources at their disposal, and enforcement of property rights and laws that pertain to infrastructure development policy. Levy and Spiller (1994; 1996) document how these factors affect the ability of regulators to maintain some independence from political pressures and to make credible long-term commitments to private investors.[3]

The solid arrows in Figure A.1 depict the fact that these (and other) factors affect directly the kind of *Regulatory Governance* system that will be required. The clarity of an agency’s roles, the degree of its autonomy, and techniques for ensuring accountability represent the foundation elements of the regulatory system. Similarly, a regulatory process that emphasizes stakeholder participation, transparency, and predictability will be more credible than one without these features. However, institutional design is just one step in the policy process. The actual *Regulatory Incentives* developed and implemented by the agency will affect the behavior and performance of regulated entities. In particular, we know that competitive pressures can be powerful determinants of industry performance, so regulatory attitudes toward entry will have a great impact on performance.

Note that many of the same factors that influence policy choice will also affect observed industry performance directly. For instance, realized production costs will generally be affected both by the prevailing production technology and by

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[3] Begara, Henisz, and Spillar (1998) find that institutions explain electric utility investment across nations.

perceptions of the government's tolerance for substantial earnings (as reflected in the use of price caps vs. rate of return). An expectation that the agency will try to “claw back” high returns (when rates are reset) dilutes incentives for cost containment. Other relevant arrows have been omitted from Figure A.1 in order to simplify the diagram.[4]

On the far right, the traditional industrial organization model depicts the chain of causation from basic conditions to industry performance. *Industry Conditions* include those factors that affect industry demand (e.g., population, income, and education) and those that affect industry supply (e.g., production technologies, operating practices, and factor prices). Basic conditions facing an industry determine the feasible number of suppliers in an industry. In turn, industry conditions are influenced by *General Economic Conditions* and by the nature of *Input Markets* (both depicted in Figure A.1). The former include macroeconomic features of a nation: employment, savings, and inflation rates, as well as the strength, stability, and diversity of its economy, its balance of trade, and the strength and stability of its capital markets. These, in turn, drive the input markets that determine the cost of key factors of production. Clearly a firm’s cash flows will be driven by national economic growth. Although this factor is beyond the control of regulators, its role needs to be recognized by stakeholders.

Finally, *International Perceptions* (of political stability, institutional support, and credibility of the regulatory process) affect the availability of external capital for private participation in infrastructure projects. Country political risk indices and ratings by financial organizations attempt to capture the risks inherent in different national settings.

Thus, the right side of the figure shows how regulatory policies (incentives) affect *Market Structure*, constrain the *Behavior* of service providers, and affect industry *Performance*. For example, regulatory policies affect entry conditions, transmission pricing, the rate of new service connections, and the degree of service unbundling. For example, there is no doubt that traditional regulation in the U.S. influenced industry structure and corporate behavior. Regulatory rules defined markets, constrained entry, and facilitated vertical integration. Thus, cost-based rate of return on rate base regulation (ROR) was designed to enable the firm to earn a fair return on its investment while protecting customers from monopoly prices. In addition, complex cost allocation procedures resulted in the sharing of capacity costs across customer groups, over markets for different services, and between geographic areas. Postage stamp (uniform) pricing was sometimes utilized, despite cost differences for serving different locations and customer groups.

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[4] See Berg (1997) for an earlier version of the Figure. The more recent *Electricity Journal* paper (Berg, 1998) presented a simplified version of this framework (Berg, 1998).

However, the old system is breaking down. Innovations and new perceptions regarding the strengths and limitations of government ownership have lead nations to

restructure the electricity sector and seek private participation in the provision of utility services.

Figure A.1 attempts to capture the key features of the environment that influence the creation of new regulatory institutions and the policy incentives they promulgate.

Balancing the Interests of Key Stakeholders

The emphasis on industry performance is not meant to diminish the importance of principles and process. Clearly, both are necessary—but not sufficient—if regulation is to be judged “best practice.” Procedures matter because of the role played by a regulatory agency in mediating among the interests of various stakeholder groups. The “classical” characterization of “independent” regulation has the agency in the middle of a triangle, balancing the interests of government, suppliers, and customers (see Figure A.2). Recognizing that institutional change requires legal mandates, the Government is often placed at the top vertex of the triangle. Government could be identified more broadly as politicians and elected officials. Or it might be defined more narrowly as a “Ministry”. However, those out of power could be in power in the future, so the agency is also mediating the interests of individuals whose time horizons extend to the next general election and others who influence public policy only indirectly. Furthermore, in federal systems, the agency might have primary responsibility for one jurisdiction, so that the interests of other agencies must be taken into account. The simple term “Government” in the balancing act begins to resemble a much more complex set of political forces.

The triangle’s vertex labeled “Suppliers” is complex for a number of reasons. So long as the entity is no longer a vertically integrated firm, an entire production chain must be considered. Market design issues are at the forefront of regulatory challenges. Incumbent firms (privately or publically-owned), recent entrants, and potential entrants all have interests in the “rules of the game” established by the agency. Access regimes, types of incentive systems (price cap vs. rate of return), and review processes all affect the cash flows for these market participants. Behind these firms are sets of equity owners, debt-holders, and managers—all of whom can have different interests regarding risks they are willing to experience and information disclosure rules adopted by the agency.

No less complicated is the interest group identified by “Customers.” The number of customer categories is endless: industrial, commercial, or residential; urban or rural (high cost areas); large or small demanders; high income or low income; served and unserved communities; technologically sophisticated and unsophisticated; today's customers versus all these groups five years from now. The balancing act within a category begins to look even more problematic than between the three archetypal groups.

So the classical characterization of the regulator as "merely" balancing the interests of three groups actually resembles a troop of jugglers with thirty different objects flying through the air at various speeds. As the number of policy objectives increase, the number of potential suppliers expands, and diverse needs of customers become recognized, the task of regulation becomes more complicated. The lesson for regulation is that a "light-handed" approach is best: forbearance when available (depending on the law), competition where feasible (depending on production technologies and market size), and all-party settlements (alternative dispute resolution) where possible.

So in principle, the agency balances all these interests in a way that promotes legitimacy to customers, credibility for investors and efficiency for the general economy—all the while recognizing the three objectives involve many sub-components that complicate the regulatory process. When the impersonal market can be used to create and allocate value, the advantage to leaving the outcomes up to market forces is that the rent-seeking activity of the various market participants is channeled away from influencing the regulatory process. In the case of many public policies, the benefits are highly concentrated, and the costs dispersed over a number of groups. For groups with high per capita potential benefits, political lobbying activity will be intense. This pattern means that some public intervention is likely to result in the aggregate costs being greater than the benefits (for example, the protection of special interests).

The next two sections focus on two key characteristics of regulation that can partially counter the likelihood of capture: transparency/participation and consultative processes that bring all the parties to the table.

Transparency and Participation

Transparency implies openness to the views of different stakeholder groups. Participation by stakeholders is one way regulators can be held accountable for their actions. How are agencies rewarded or punished? First, budgets can be expanded or cut, based on the perceived performance of the agency (and the sectors it regulates). Second, recognition can be given to key personnel who have a significant impact on agency policy implementation and on sector performance. Third, legislative and executive oversight can serve as a vehicle for monitoring agency activities. In addition, McCubins and Schwartz (1984) emphasize the role of interest groups as providing additional information to politicians regarding agency activities: such groups trigger "fire alarms" if the bureaucracy strays from its legislative mandate.

In the case of regulated industries, incumbent suppliers can obtain information rents because they have more information on demand patterns and cost structures. Other interest groups, including potential entrants, have an interest in bringing out some of that information. Policy makers will find it helpful to have administrative processes that facilitate the development of more comprehensive information. Thus, communication and consultation are important principles for effective regulation.

Of course, various stakeholders (with interests that diverge from the incumbent) will tend to present biased information. However, policy makers have the advantage of eliciting a diverse set of perspectives in the context of open proceedings. Furthermore, factual information can be challenged, so the various participants will tend to build sound (as opposed to “biased” cases) for their positions. Thus, administrative procedures can structure participation so as to produce policies based on more comprehensive information.

Note that unless formal and informal processes are in alignment, transparency can be threatened. For example, in the Argentina natural gas sector, the law requires the regulatory agency, Enargas, to document the sources of cost-savings implicit in the X-factor applied to distribution companies in a price control review. This requirement has been interpreted as requiring the agency to develop cost-containment programs that the company could adopt to achieve these savings. In the recent price review, the agency also examined total factor productivity numbers to gauge the feasibility of plans. The key point here is that the formal process (agency identification of firm cost-containment programs—as required by law) might diverge from the actual process used to estimate X.

It is surely problematic to have regulators identifying specific plans for cost containment (an improved meter reading program, just-in-time inventory initiatives, etc.) So in practice, the creation of recommended projects becomes a *formal* mechanism for ratifying a more realistic *informal* process for quantifying X. It seems such a “shadow” process increases regulatory discretion and reduces transparency. However, if the legal framework makes such an approach necessary, this “second best” approach is better than the alternative—in this case, micromanagement.

Consultation and Alternative Dispute Resolution

Stern and Holder identify participation as one of their six criteria for sound regulation. They recognize that both communication and consultation are necessary if stakeholders are to be informed of rules and allowed to contribute to regulatory discussions. Broad policy will have been established in legislation, but the agency will still have to interpret and apply the law in the context of the facts. Identifying that “reality” becomes a task for market participants. As the number (and diversity) of market participants expands, the use of the traditional adversarial hearing process in the U.S. is being supplemented (if not replaced) by alternative dispute resolution (ADR) procedures.

It is said that “Settlements make winners—Hearings make losers.” Nevertheless, the dispute resolution process matters. Three approaches from Canada illustrate the strengths and limitations of various approaches to ADR (Grant, 1999). First, consider the Ontario Energy Board. Utilities provide a detailed application to the Board to initiate negotiations. Although Board staff members attend discussions, they are to provide general information—not take positions in the negotiations. Once a settlement is reached, the Board reviews the agreements on an issue-by-issue basis, making changes. The rationale for such intervention is that the parties might not reach an agreement in the public interest. However, individual issue review reduces the likelihood that stakeholders will make trade-offs (compromises) that yield win-win outcomes, since participants realize that the Board can overturn portions of the agreement. The result is few actual settlements are achieved.

The case of the National Energy Board is quite different. No application is placed before the Board. Staff members do not participate in the meetings (so they are not in much of a position to evaluate the final settlement). Thus, the Board either approves or rejects the settlement document. While numerous settlements between shippers and pipelines have emerged from these negotiations (involving pricing flexibility and mutually beneficial incentives), the system is not at all transparent to the general public.

Finally, consider the British Columbia Utilities Commission. The utility submits a full application, outlining the issues to be resolved. Workshops and information requests promote transparency, with commission staff actively participating in the negotiations. Nearly 100 percent of the settlement processes have been successful (and approved by the Commission)—reducing the cost of regulation and speeding up what can be a cumbersome process. Grant (1999) maintains that the B.C. system has stimulated utilities to work closely with customers, yielding improved performance for suppliers and customers. On the surface, the last system seems to be closer to “best practice,” but additional analysis would be needed for a definitive conclusion. In particular, do agency staff operate in a heavy-handed manner in this attempt at “light-handed” regulation?

Concluding Observations

Since regulatory agencies are basically setting constraints on corporate behavior, those implementing public policy need to understand what is driving decisions in the marketplace. A brief review of market processes can help us identify the challenges facing regulators who are trying to simulate competitive outcomes.

How do firms create value? First, they create value by lowering costs. Valuable resources are freed up and used in other sectors of the economy. Second, since value is in the eyes of the consumer, value is created when product quality improvements or entirely new products better meet the needs of consumers. In competitive markets, firms creating value are able to capture profits from their risk-taking activity. Economic profits represent returns to equity investors who put their capital at risk. Normal returns arise from normal performance. Above-normal returns arise from superior performance (reflecting best-practice in operational effectiveness and selection of a strategy that meets the preferences of consumers and builds on the capabilities of the firm).

There are clear links between economic principles and business decision-making. Investors respond to signals provided by the securities markets and firms enter and exit markets based on profit expectations. Similarly, incentives established by regulators (including entry policies and access regulation) have significant impacts on what firms do and how they do it. Unless agencies understand the processes underlying decisions in an unregulated setting, they will be unable to do a good job of meeting public policy objectives through appropriate selection and use of policy instruments. In particular, by encouraging firms to create value (via cost-containment and the introduction of valued new services) regulators can enhance industry performance. However, if poor incentives are established, value can be destroyed, as investors withdraw capital from the industry or costs drift upward in response to cost-of-service regulation. The art of regulation involves establishing rules that allocate value to consumers and suppliers in such a way as to maintain incentives for the firm to create value, while promoting political legitimacy in the eyes of consumers and other stakeholders.

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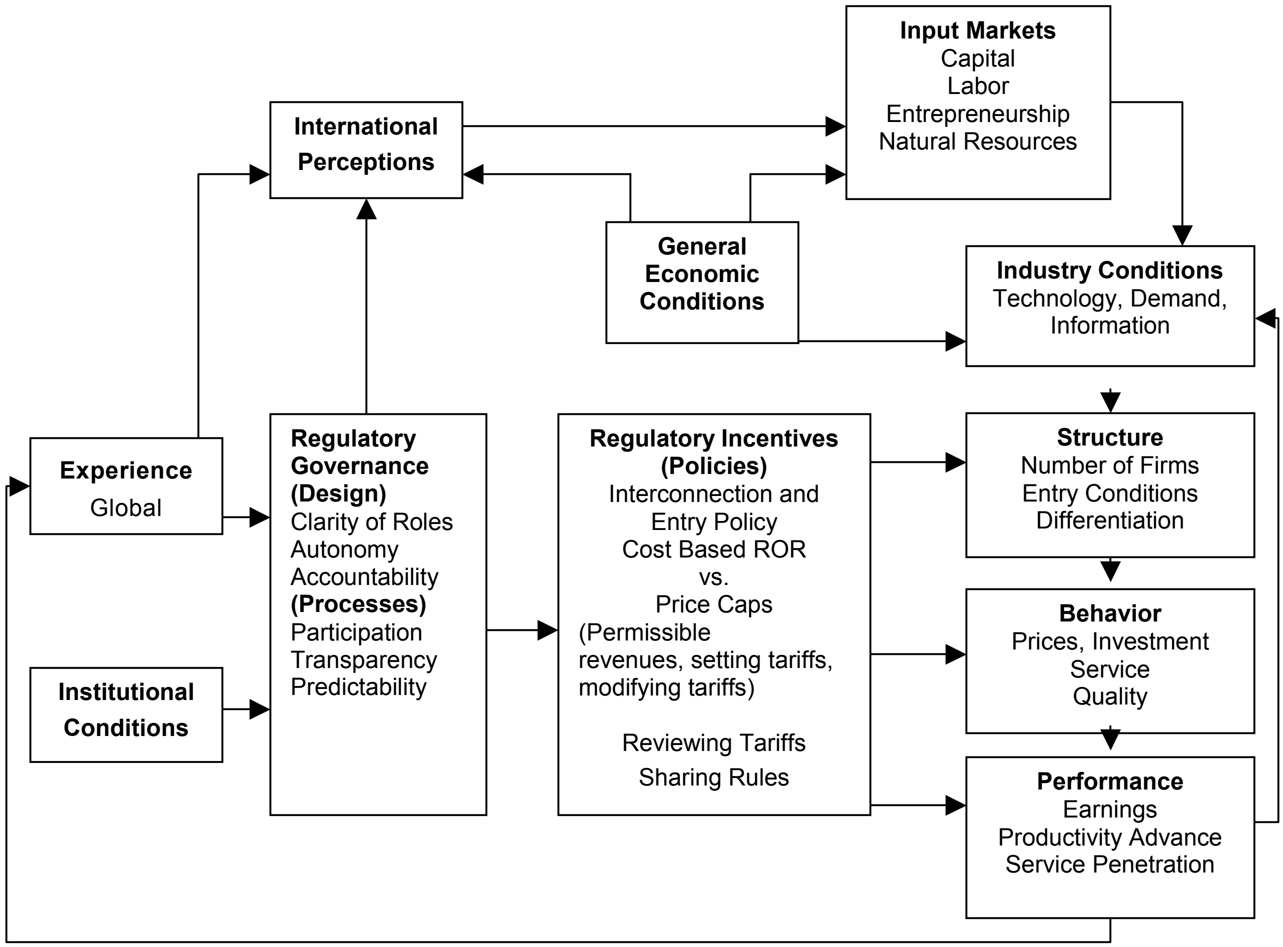

Figure 10.1 Regulatory Governance, Incentives and Performance

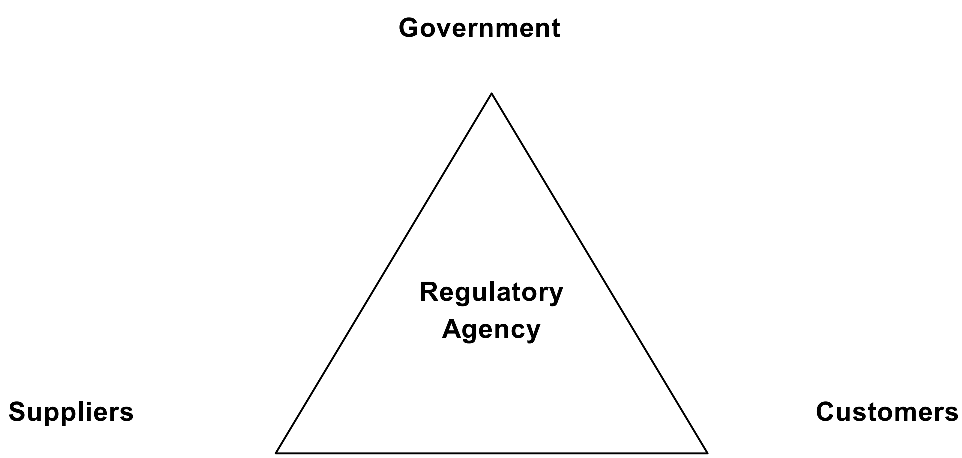

Figure 10.2 Classical Independent Regulation: "Balancing" Interests

UTAH THANKSGIVING SNOWSTORM – AS REPORTED BY PACIFICORP ON DECEMBER 2001

From November 23-26, 2001 heavy wet snow fell in the Wasatch Bench area. This included high winds that caused damages to power lines in the form of broken poles and downed wires. There were many trees that fell into the power lines.

Approximately 116,000 Utah Power and Light customers were impacted by the storm. As such, it was classified as a "Major Event".

The lessons learned, and the resulting actions, from the storm are to:

- **Create firm criteria on when to implement the Emergency Management Plan**

  Three levels have been designated: (1) Warning – establishing a state of readiness; (2) Distribution Region Emergencies – no cross regional or external assistance required; and, (3) Multiple Region Emergencies – significant outages lasting more than 24 hours.

- **Complete the emergency management training throughout Utah Power…**

  This was completed June 2001 and given a final mock drill in July 2001.

- **Review the telephony capacity…**

  Upon investigation, the telephone system functioned as it was designed. However, PacifiCorp continues to examine further options to handle high-volume call surges.

- **Improve the recorded messages…**

  A cross-departmental Service Level Agreement was created between the Dispatch and Customer Service Department.

- **Improve internal communication process to keep customer service employees updated…**

  Emergency Action Centers have been designated, with communication provided via broadcast emails.

Tree trimming has been conducted on 1,760 miles of distribution line in Utah from January through November 2001. The majority of outages experienced were due to heavily weighted trees and limbs from outside the right of way.